National Energy Technology Laboratory

Carbon Sequestration Program Environmental Reference Document

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Disclaimer

About This Document

This Environmental Reference Document has been prepared by the United States Department of Energy (DOE) to provide an examination and review of the environmental considerations of carbon sequestration technologies that could be demonstrated or implemented under DOE's Carbon Sequestration Program. This document will help serve as a resource for DOE and its partners in determining the potential environment aspects of future projects and will aid project proponents in site selection considerations and to institute Best Management Practices (BMPs) to avoid adverse environmental impacts.

DOE thanks the many people who contributed to this document.

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1.0 BACKGROUND

1.1 INTRODUCTION

This Environmental Reference Document has been prepared by the United States Department of Energy (DOE) to provide an examination and review of the environmental considerations of carbon sequestration technologies that could be demonstrated or implemented under DOE's Carbon Sequestration Program. This document will help serve as a resource for DOE and its partners in determining the potential environmental aspects of future projects and will aid project proponents in site selection considerations and to institute Best Management Practices (BMPs) to avoid adverse environmental impacts. The National Energy Technology Laboratory (NETL) is a multi-purpose laboratory owned and operated by the DOE Office of Fossil Energy and is the primary DOE office implementing the Carbon Sequestration Program (hereafter referred to as "the Program"). NETL has a mission to implement a research, development, and demonstration program to resolve the environmental, supply, and reliability constraints of producing and using fossil energy resources.

In general, DOE will use this Environmental Reference Document to:

- Identify potential environmental issues and impacts associated with implementing Program technologies that should be addressed in future site-specific NEPA documents;
- Identify aspects of site-selection for future projects that must be considered (e.g., avoidance of sole-source aquifers);
- Identify general BMPs for planning, constructing and operating future projects;
- Provide an overview of general mitigation measures that could be applied to future projects.

1.2 U.S. GLOBAL CLIMATE CHANGE INITIATIVE

The U.S. Global Climate Change Initiative (GCCI) was signed on February 14, 2002, which calls for an 18 percent reduction in the carbon intensity [expressed in kilograms of carbon dioxide (CO_2) emitted per unit of economic activity] of the United States (U.S.) economy by 2012. By focusing on carbon intensity as the measure of success, this strategy promotes vital climate change R&D while minimizing the economic impact of greenhouse gas (GHG) stabilization in the U.S. Technology solutions that provide energy-based goods and services with reduced GHG emissions are the preferred approach to achieve the GCCI goal. The GCCI also calls for a progress review relative to the goals of the initiative in 2012, at which time decisions will be made about additional implementation of CO_2 reduction measures.

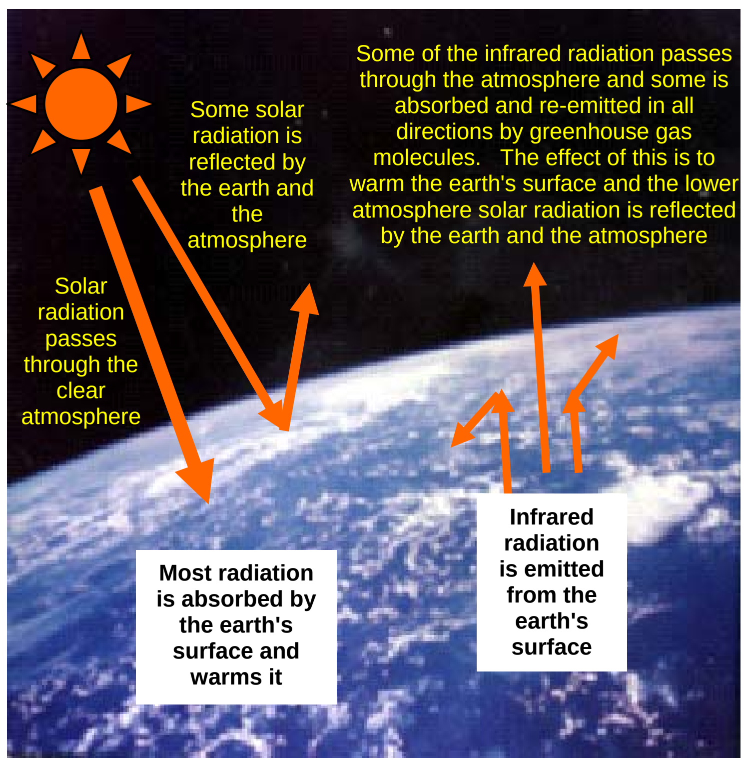


Figure 1-1. The Greenhouse Effect

The DOE established the Carbon Sequestration Program in 1997 with the focus of conducting research and development (R&D) activities to evaluate and develop carbon sequestration technologies. Carbon sequestration involves capturing and storing CO_2 emissions prior to release into the atmosphere, as well as enhancing natural carbon uptake and storage processes. CO_2, water vapor, and other gases exert a "greenhouse" effect that traps heat within the Earth's troposphere and which has, thus far, maintained the planet's temperate climate (Figure 1-1). Although CO_2 is a natural and important component of the atmosphere—animals and plants produce CO_2 during respiration, and plants need it for photosynthesis—global emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty-one billion metric tons per year in 2003. The most notable human activity associated with the generation of CO_2 is the combustion of carbon-based fuels (including oil, natural gas, and coal). Many scientists, including the Intergovernmental Panel on Climate Change (IPCC), recognize a danger that even a modest increase in the Earth's temperature (called "global warming") could alter the global climate and cause significant adverse consequences for human health and welfare (NETL, 2004a).

> CO_2, water vapor and other gases exert a "greenhouse" effect that traps heat within the Earth's troposphere. Strong evidence is emerging that increased GHG emissions are causing climate change impacts.

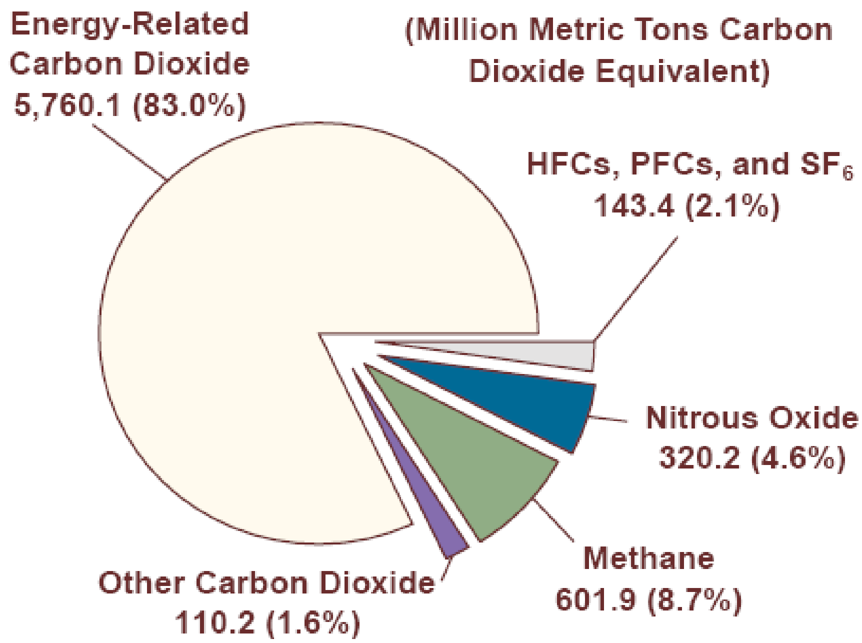
1.2.1 Current Status of Greenhouse Gas Emissions

Six gases—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—have been identified as the primary contributors to the greenhouse effect. The individual emissions of these gases can be multiplied by the appropriate Global Warming Potential (GWP), which is an indexed ratio used to produce a CO_2 emissions equivalent. GWPs discussed in this document are those calculated over a 100 year time horizon. Because each gas has a different warming effect (e.g., a gram of CH_4 has roughly 23 times the warming effect of a gram of CO_2), the use of the GWP allows the warming effects of the different gases to be compared on an equal basis using CO_2 as the reference gas. On this basis, three gases (CO_2, CH_4, and N_2O) comprise 98 percent of GHG emissions (Energy Information Administration (EIA), 2004), and CO_2 far surpasses other GHGs both in quantity emitted and in its relative contribution to climate change effects (Figure 1-2). Thus, CO_2 is the primary focus of mitigation efforts for GHG emissions.

The combustion of fossil fuels by all energy sectors and sources contributes to CO_2 emissions (Figure 1-3). Electric power generation represents one of the largest CO_2 emitters in the U.S. The CO_2 emissions from electricity generation by power plants burning fossil fuels in the U.S. increased by 23.5 percent between 1990 and 2000 (EIA, 2001), and nearly two fifths of human-caused CO_2 emissions in the U.S. come from these plants (EIA, 2004). The geographic distribution of CO_2 emissions from U.S. power plants in million metric tons (MMT or million metric tons) is illustrated in Figure 1-4.

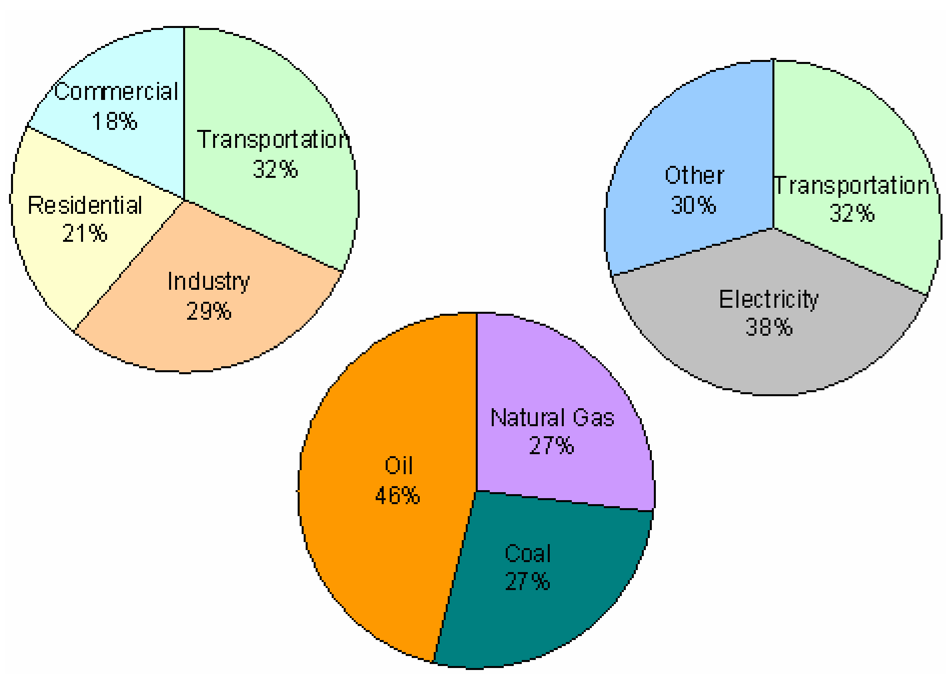
Low-cost reliable energy is one of the foundations of the U.S. economy. In 1999, the U.S. consumed 3 kilowatt-hours of energy for each dollar of economic activity, and 85 percent of that energy came from fossil fuel resources (coal, oil, and natural gas). In 2002, the U.S. generated 98 quadrillion British thermal units of energy, 86 percent of which was produced from fossil fuels. The EIA (2004) projects that U.S. consumption of coal, oil, and natural gas will increase by 40 percent over the next 20 years, while GHG emissions are projected to rise 33 percent over the same period. Because demand for electricity is expected to grow, and fossil fuels will continue to be the dominant fuel source, power generation can be expected to provide even greater contributions to GHG emissions in the future.

> The Energy Information Administration (EIA) projects that U.S. consumption of coal, oil and natural gas will increase 40 percent over the next 20 years, while GHG emissions are projected to rise 33 percent over the same period.



Source: EIA, 2004.

Figure 1-2. Composition of Greenhouse Gas Emissions (CO_2-Equivalent Basis)



Source: EIA, 2005.

Figure 1-3. Contributions to CO_2 Emissions by Energy Sectors and Sources (2003)

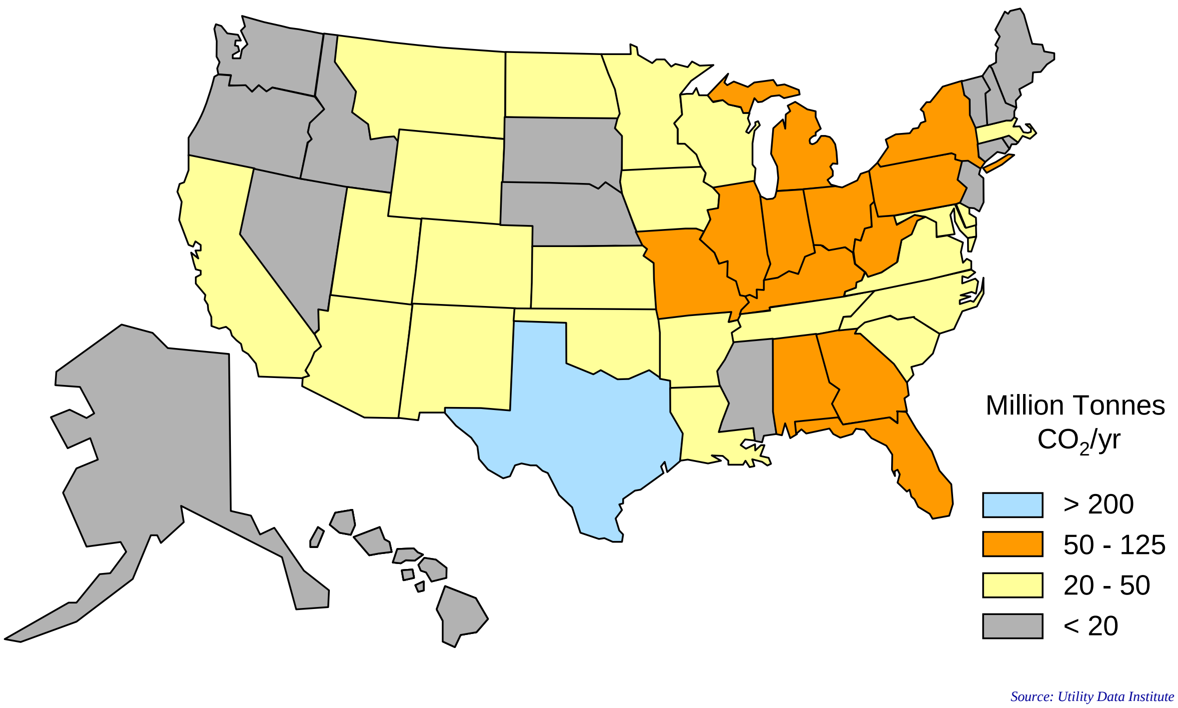
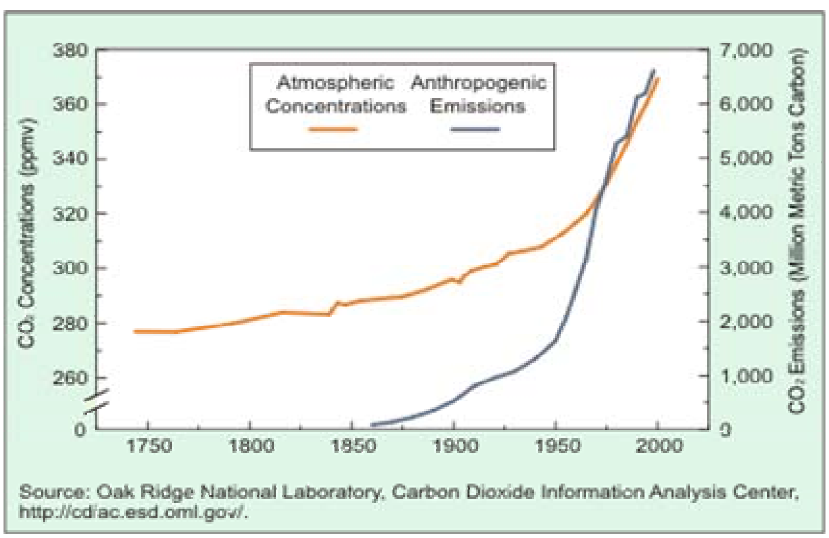


Figure 1-4. Distribution of CO_2 Emissions by U.S. Power Plants



Source: ORNL, 2007.

Figure 1-5. Historical Comparison of Atmospheric CO_2 Concentrations and Anthropogenic Emissions

Strong evidence is emerging that GHG emissions are linked to potential climate-change impacts. As illustrated in Source: ORNL, 2007.

Figure 1-5, concentrations of CO_2 in the atmosphere correlate with anthropogenic emission increases over the last 150 years. Concentrations of CO_2 in the atmosphere have increased rapidly in recent decades, and the increase correlates with the rate of world industrialization, such that in the last 100 years, atmospheric CO_2 concentrations have increased from approximately 280 parts per million (ppm) to nearly 380 ppm (NETL, 2004a).

1.2.2 Future Projections of Greenhouse Gas (GHG) Emissions

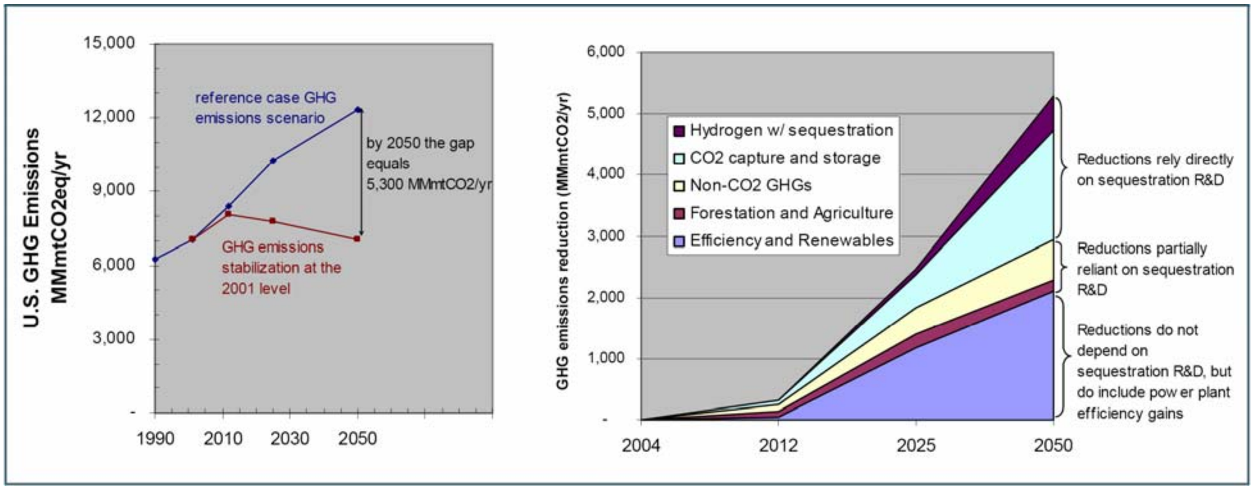
Today, the atmosphere contains 33 percent more GHGs than it did prior to the industrial revolution, and the concentration is increasing steadily at a rate of more than 1 ppm per year (NETL, 2004a). It was reported in 2002 and 2003 that the annual increase was more than 2 ppm (Brown, 2004). It is generally recognized that anthropogenic GHG emissions are having a significant effect on global climate and that GHG emissions may need to be controlled to avoid future adverse impacts. Hence, in 1992 the U.S. and 160 other countries ratified the Rio Treaty, which calls for "…stabilization of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." What constitutes an appropriate level of GHG in the atmosphere remains open to debate, but even modest scenarios for stabilization would eventually require a reduction in worldwide GHG emissions of 50 to 90 percent below current levels (NETL, 2004a).

The Program has developed scenarios for domestic GHG emissions to the year 2050, which help to quantify the potential need for advanced carbon sequestration technologies that may stabilize GHG concentrations. In Figure 1-6, the upper curve in the graph on the left represents a reference-case GHG emissions scenario. It assumes significant development and implementation of technologies for low- or no-carbon fuels and improved efficiency, but it does not include direct incentives for GHG emissions reduction. The lower curve in the left graph represents an emissions-stabilization scenario. It assumes accelerated reductions in GHG intensity through 2012 with gradually reduced emissions thereafter. The goal is to stabilize emissions at the 2001 level. The required emissions reduction, which equals the gap between the two scenarios, grows to 5,300 MMT of CO_2 per year by 2050. Emissions stabilization is a first step toward atmospheric concentration stabilization. This would require emissions to be reduced by 80 to 90 percent below current levels (NETL, 2004a).

The graph in Figure 1-6 shows the contributions of various mitigation options needed to meet the gap under the emissions stabilization scenario. The DOE has estimated the contribution of each option by using an internal planning model that is based on cost/supply curves. Although "Efficiency and Renewable" sources are generally less expensive to implement and will be important components, they cannot alone meet the total reduction goals indicated by the gap. Two options, "CO_2 capture and storage" and "Hydrogen with Sequestration", are directly dependent on research conducted by the Program. Together, the two options account for 45 percent of total emissions reduction in 2050 under the emissions stabilization scenario. Two other options, "Forestation and Agriculture" and "Non-CO_2 GHGs" control, which are being pursued by the Program in concert with other public and private partners, contribute another 15 percent. Clearly, carbon sequestration technology will play a pivotal role should GHG stabilization be deemed necessary (NETL, 2004a).

> "Value-added" sequestration applications, such as enhanced oil recovery, can provide a cost-effective means for reducing CO_2 emissions and offer collateral benefits through increased domestic production of oil and natural gas.

By working with market growth and capital stock turnover, the stabilization strategy allows time for new technology and low-cost options to evolve. It also prevents a rapid increase in GHG emissions during the next 50 years, thus reducing the potential need for steep, economically disruptive reductions in the future. Over the next 20 to 30 years, "value-added" sequestration applications, such as enhanced oil recovery (EOR), can provide a cost-effective means for reducing CO_2 emissions and offer collateral benefits through increased domestic production of oil and natural gas. In the mid- and long-term, even more advanced CO_2 capture technology and integrated CO_2 capture, storage, and conversion systems can provide cost-effective options for deep reductions in GHG emissions. The premise of the analysis is that the sequestration options would not be available without an aggressive R&D effort. Thus, the economic benefits result from a reduced cost of GHG emissions mitigation.



Source: NETL, 2004a.

Figure 1-6. Pathway to Stabilization Strategy

1.2.2.1 The Stabilization Triangle

To understand the relative degree to which carbon sequestration and other carbon mitigation approaches can contribute to solving the greenhouse gas problem, researchers with the Carbon Mitigation Initiative (CMI) developed a tool called the "stabilization triangle". Through CMI, over 60 researchers in science, engineering, and policy are developing strategies to reduce global carbon emissions safely, effectively, and affordably (CMI, 2004).

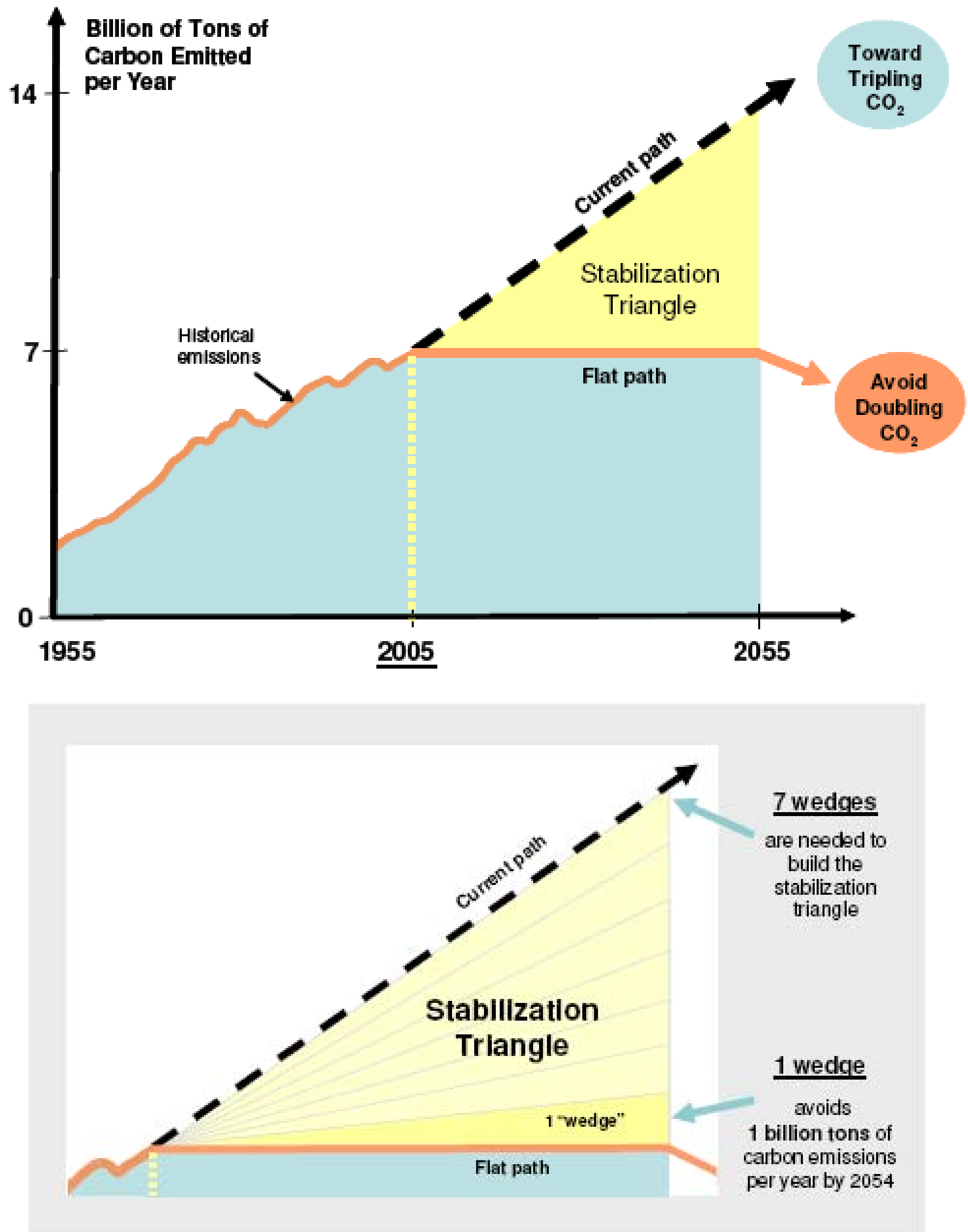
CMI predicts that to keep emissions of CO_2 flat for 50 years, CO_2 output must be reduced by approximately 7 billion tons per year by 2054. These reductions are depicted as the "stabilization triangle". Within this triangle, strategies for meeting this reduction goal are referred to as "wedges" of the triangle. If each wedge reduced carbon by at least 1 billion tons per year by 2054, seven wedges would be required to stabilize emissions (CMI, 2004) (Figure 1-7).

The CMI identified 8 strategic areas and 15 specific goals or "wedges" that could achieve this rate of carbon reduction. The 8 strategic areas are:

- Efficiency
- Fuel Switching
- Carbon Capture and Storage
- Nuclear Power
- Wind Power
- Solar Power
- Biomass Fuels
- Natural Sinks (terrestrial sequestration)

Specific goals comprising the 15 wedges are shown in Figure 1-8.

While many strategies will be needed to stabilize carbon emissions over the next few decades, this document focuses on DOE's program related to Carbon Capture and Storage and Natural Sinks. Other federal programs that focus on other GHG reduction strategies are discussed in Appendix A.



Source: CMI, 2004.

Figure 1-7. The Carbon Stabilization Triangle

Source: CMI, 2007.

Figure 1-8. Strategies to Build the Stabilization Triangle

1.3 PROGRAM OVERVIEW

The Program encompasses all areas of carbon sequestration (Figure 1-9) including the following principal components: Core R&D; Infrastructure Development; Integration; and Program Management. Summary level information on each of these components is presented in the following sections.

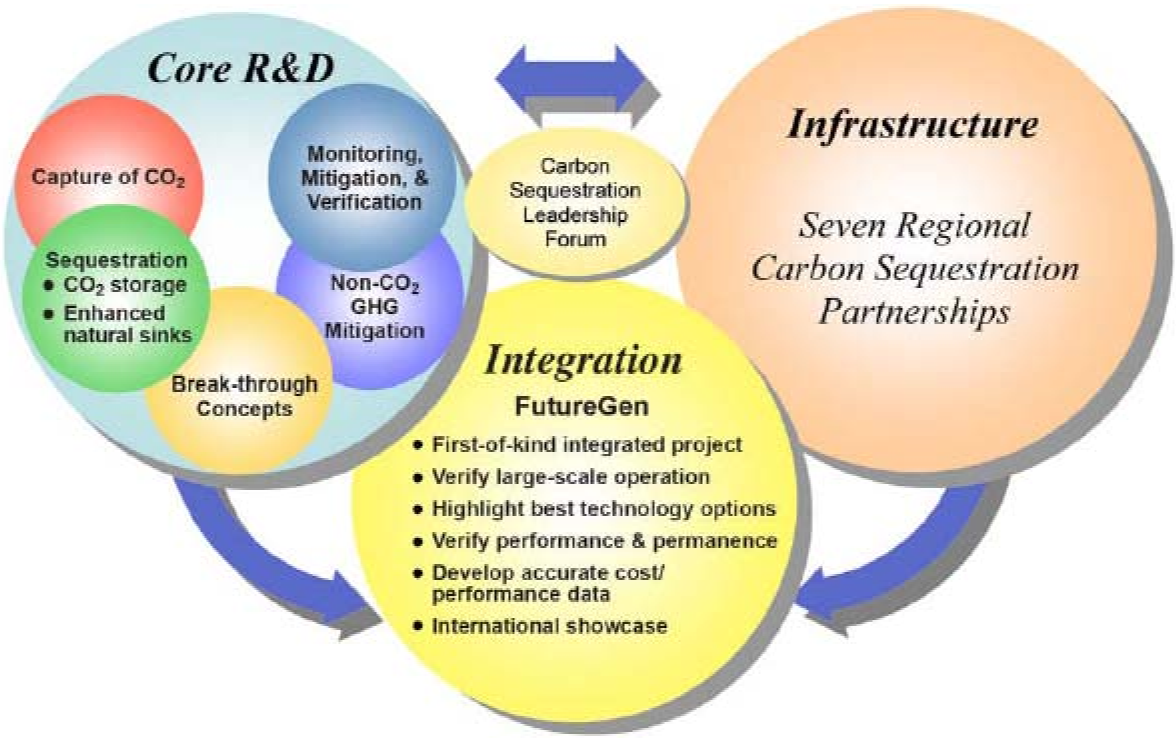


Figure 1-9. Carbon Sequestration Program Structure

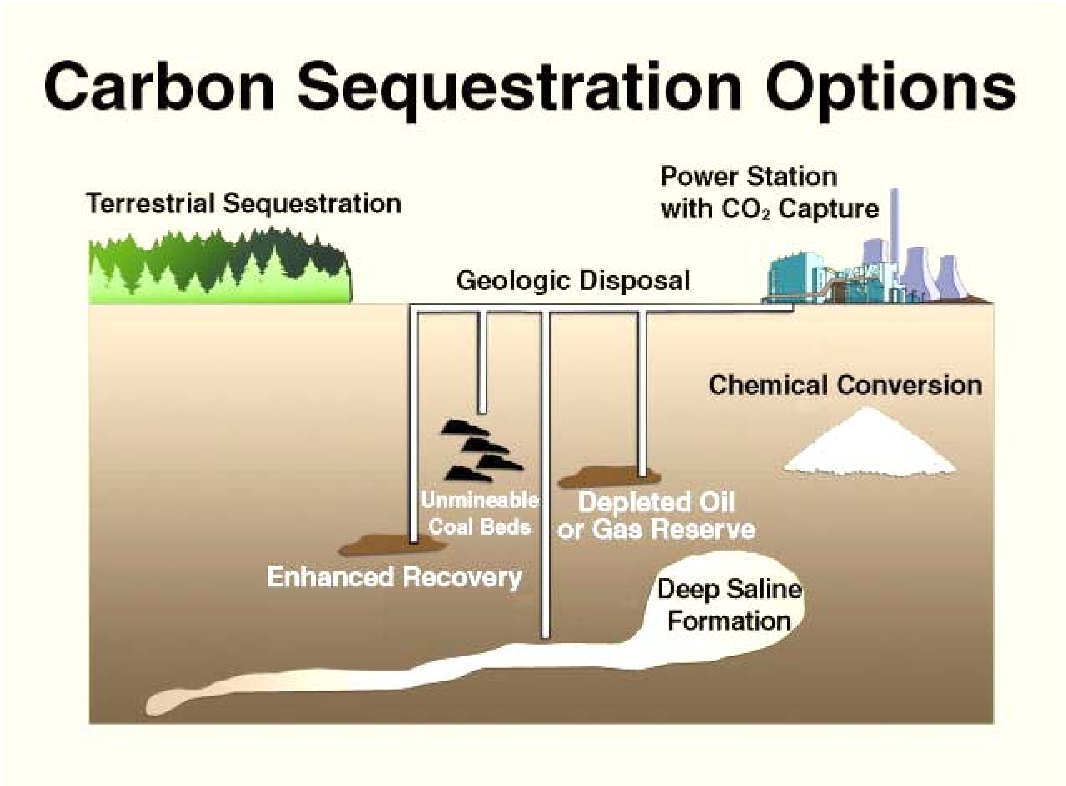
1.3.1 Core R&D

Core R&D includes the laboratory, pilot plant, and field efforts necessary to develop new technologies and new systems for GHG mitigation. As depicted in Figure 1-9, the Core R&D component of the Program consists of the following five major elements.

- CO_2 Separation and Capture – Development and demonstration of technologies to efficiently separate CO_2 from emissions sources or the atmosphere, and recovering of a concentrated stream of CO_2 that is amenable to sequestration or conversion.
- Sequestration – Development and demonstration of technologies for the placement of CO_2 into a repository so it can be stored for long periods of time (hundreds to thousands of years). The potential pathways for storage are geologic sequestration and terrestrial sequestration.
- Monitoring, Mitigation, and Verification (MM&V) – Development and demonstration of technologies to measure the amount of CO_2 stored at a specific sequestration site, monitoring the integrity of the storage site over time and mitigating against the potential for leakage. This includes verifying that the CO_2 is remaining stored as predicted and is not harming the host system or presenting risks to human health or the environment.

- Breakthrough Concepts – The pursuit of unique, revolutionary, and transformational approaches to CO_2 sequestration that offer the potential for low cost, permanence, and global capacity.
- Non-CO_2 GHG Mitigation – The pursuit of methods to reduce or avoid methane emissions by integrating abatement with energy production, conversion, and use. The U.S. Environmental Protection Agency (EPA) is the lead agency for this effort to assess the role that non-CO_2 emissions abatement can play in a nationwide strategy for reducing GHG emissions intensity. DOE's Carbon Sequestration Program will coordinate with EPA on this initiative, however, as this document focuses on carbon sequestration only, non-CO_2 GHG mitigation is not be addressed.

The Program places a strong focus on direct capture of CO_2 emissions from large-point sources with subsequent storage in geologic formations (see Figure 1-10). These large-point sources, such as power plants, oil refineries, and industrial facilities, are the foundations of the U.S. economy. Reducing net CO_2 emissions from these facilities complements efforts to reduce emissions of particulate matter, sulfur dioxide, and nitrogen oxides. It also represents a progression toward fossil fuel production, conversion, and use with little or no detrimental environmental impact. Through its core R&D efforts, the Program also has engaged federal and private sector partners that have expertise in certain technology areas such as the U.S. Department of Agriculture (USDA) and electric utilities in terrestrial sequestration, the U.S. Geologic Survey (USGS) and the oil industry in geologic sequestration, the National Academies of Science (NAS) in breakthrough concepts, the EPA and Non-Governmental Organizations (NGOs).



Source: The White House, 2006.

Figure 1-10. Primary Carbon Sequestration Options

1.3.2 Infrastructure Development – Regional Partnerships

DOE selected seven Regional Partnerships in 2003 with the goal of evaluating and pursuing opportunities for carbon sequestration deployment (see Figure 1-11). For the purposes of this reference document, the affected environment focuses on the regions defined by the Regional Partnership effort. This approach is justified by the regional diversity of carbon sequestration opportunities as well as the regional and local differences in natural resources and the potential impacts of sequestration technologies.

The Regional Partnerships include more than 300 state agencies, universities, non-governmental organizations, and private companies. Each Partnership is focused on a specific region of the country, taking into consideration the local ecosystem, the local geology, and the types of CO_2 emissions sources and sinks found in the region. Together the seven Partnerships provide a network of capability, knowledge, and infrastructure to enable carbon sequestration technology to play a major role in a national strategy to mitigate GHG emissions. These Partnerships are screening their respective regions for significant CO_2 sources and sinks, and they will establish necessary MM&V protocols. The Partnerships will support the development of infrastructure needed to validate and deploy sequestration technologies, and they will address the regulatory, environmental, and outreach issues associated with priority sequestration opportunities in the region.

> Regional Carbon Sequestration Partnerships are generally comprised of state agencies, universities, non-governmental organizations and private companies. Together, the 7 Regional Partnerships provide a network of capability, knowledge and infrastructure to further the goals of the Program.

The Partnerships that will implement carbon sequestration projects include:

- West Coast Regional Carbon Sequestration Partnership (WESTCARB)
- Big Sky Carbon Sequestration Partnership
- Southwest Regional Partnership on Carbon Sequestration
- The Plains CO_2 Reduction Partnership (PCO_2R)
- Midwest Geologic Sequestration Consortium (Illinois Basin)
- Midwest Regional Carbon Sequestration Partnership (MRCSP); and
- Southeast Regional Carbon Sequestration Partnership (SECARB)

These Partnerships were selected after a competitive process, which motivated the awardees to assemble teams of highly qualified experts and to offer an average 39 percent cost share for project implementation. The partnership approach is partitioned into three phases:

- Characterization (Phase I) – This phase was structured to be a scoping, assessment, screening, and outreach/education effort and was completed in June 2005. During this Phase, the Partnerships characterized their opportunities for sequestration, the sources in their region, infrastructure for transportation of CO_2, ad the regulatory requirements to implement future tests.
- Validation (Phase II) - The Partnerships are validating the storage opportunities identified previously through a series of field validation tests.
- Deployment (Phase III) – The Partnerships will develop large volume sequestration tests where up to 1 million metric tons of CO_2 will be stored in different geologies of North America.

More information regarding the Regional Partnerships can be found at http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html.

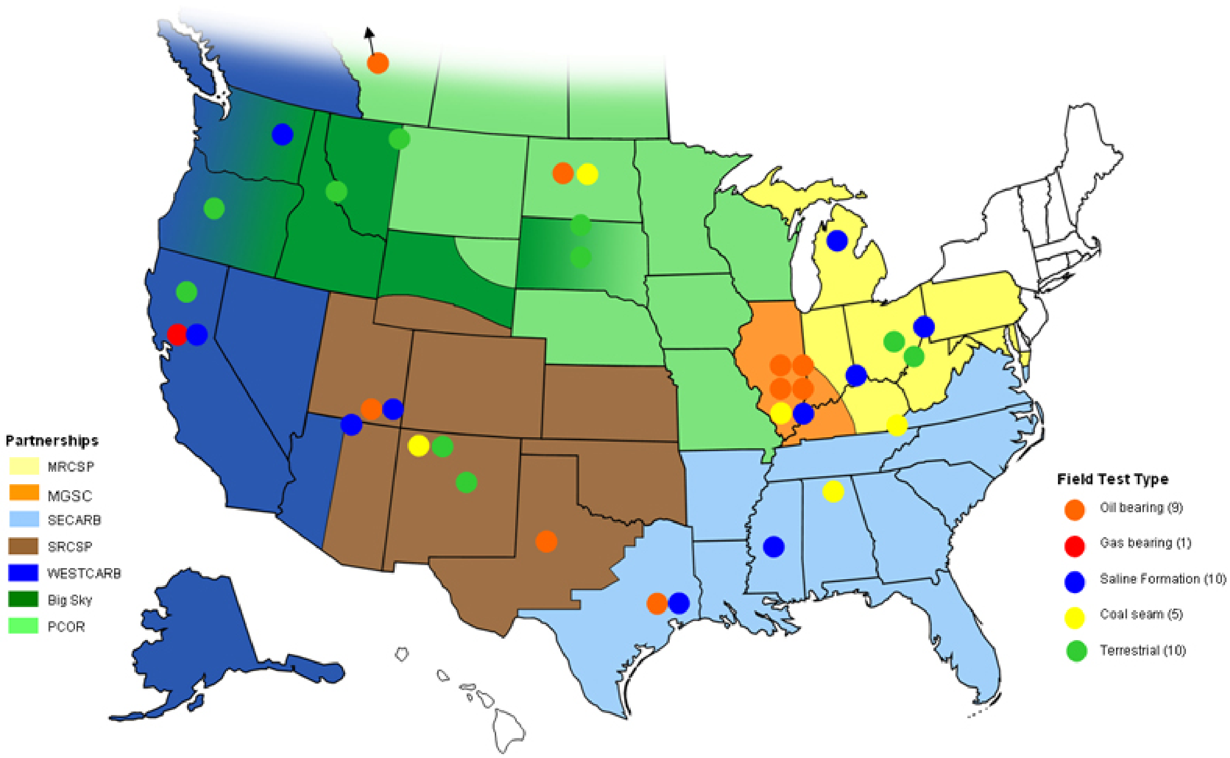


Figure 1-11. Regional Partnerships

The Partnerships are producing materials and data relating to the following information within their respective regions:

- Carbon sequestration atlases illustrating and describing the point sources of CO_2 emissions, geologic formations that have potential for CO_2 storage, and opportunities for terrestrial sequestration.
- Project implementation plans identifying the most promising terrestrial and/or geologic sequestration projects in each region.
- Action plans for regulatory compliance identifying the areas of increased understanding, sequestration technology performance metrics, MM&V capability, and risk assessment requirements needed to address and comply with environmental regulations.
- Action plans for public outreach and education setting forth methods for public engagement and tools for stakeholder education.

1.3.3 Regional Partnerships' Validation Phase Projects

The seven Regional Partnerships projects were selected by DOE in 2005 to implement field tests and validate carbon sequestration technologies that are best suited to their respective regions. They will also evaluate the most promising regional repositories for CO_2. As part of this effort, the Partnerships will also conduct public outreach, satisfy permitting requirements, and identify best-management practices for future deployment activities. The Partnerships are led by public-private sector consortiums of businesses, state agencies, and universities (DOE, 2005).

The selected Regional Partnerships and a summary of their projects follow:

- **Big Sky Regional Carbon Sequestration Partnership** will demonstrate geologic storage in mafic/basalt rock formations, which hold significant potential for long-term storage of CO_2. For example, the Big Sky region's Columbia River Basalt area could store an estimated 30 years of CO_2 emissions from all U.S. coal-fired power plants. The Partnership, headed by Montana State University, is evaluating opportunities to design cropland and forestland field test sites. The covered states include Montana, Wyoming, South Dakota, Idaho, and eastern Washington and Oregon. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/bigsky.pdf.
- **Midwest Geological Sequestration Consortium-Illinois Basin** will determine the ability, safety, and capacity of geological formations to store CO_2 in deep coal seams, mature oil fields, deep saline formations, and organic-rich shales of the Illinois Basin. The consortium is conducting six small-scale sequestration field tests in depleted oil and gas fields, a saline formation, and unmineable coal seams to assess the ability of the formations to sequester a portion of the 276 million tons of CO_2 emitted annually from fixed sources in the Illinois Basin. The Partnership is led by the University of Illinois-Illinois State Geological Survey. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/mgsc.pdf.
- **Midwest Regional Carbon Sequestration Partnership** is conducting at least three small-scale CO_2 injection field tests in the region's deep geologic saline formations, which have more than 200 years of storage capacity, to demonstrate the safety and effectiveness of geologic sequestration systems. The Partnership will also conduct small-scale terrestrial sequestration field tests to demonstrate measurement techniques associated with carbon storage and will monitor how carbon credits can be traded in voluntary greenhouse gas markets. Battelle Memorial Institute located in Columbus, Ohio, heads the Midwest Partnership, which covers Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/mrcsp.pdf.
- **Southeast Regional Carbon Sequestration Partnership** is defining the potential for storing CO_2 in three field sequestration validation tests in four target geologic formations. The field tests include: enhanced oil recovery and saline stacked formations, unmineable coal seams, and saline formations. The region covers Georgia, Florida, South Carolina, North Carolina, Virginia, Tennessee, Alabama, Tennessee, Mississippi, Arkansas, Louisiana, and southeast Texas. The Partnership is led by Southern States Energy Board, Norcross, Ga. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/southeast.pdf.
- **Southwest Regional Partnership for Carbon Sequestration** is conducting five field tests (three geologic, two terrestrial) to validate the most promising carbon sequestration technologies and infrastructure concepts. The Partnership geologic sequestration tests are located in Utah, New Mexico, and Texas, as well as region-wide terrestrial analysis. The tests represent a variety of carbon sink targets, including deep saline sequestration, enhanced oil recovery and sequestration, enhanced coalbed methane production, and geologic sequestration tests combined with terrestrial tests. The Southwest Partnership includes the states of New Mexico, Oklahoma, Kansas, Colorado, Utah, and portions of Texas, Wyoming, and Arizona. The Partnership is coordinated by the New Mexico Institute of Mining and Technology. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/southwest.pdf.
- **Plains CO_2 Reduction Partnership** is conducting four technology validation field trials and two investigations of carbon sequestration concepts. The field trials will involve storage of CO_2, comprehensive monitoring, and mitigation in depleted oil and gas formations, unmineable coal seams and restoration of wetlands. The Plains Partnership includes North Dakota, South Dakota, Minnesota, Montana, Wyoming, Nebraska, Iowa, Missouri, and Wisconsin, along with the Canadian provinces of Alberta, Saskatchewan, and Manitoba. The Partnership is led by the

Energy & Environmental Research Center at the University of North Dakota, Grand Forks. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/pcor.pdf.

- **West Coast Regional Carbon Sequestration Partnership** will conduct two CO_2 storage tests in California and one in Arizona related to CO_2 storage in depleting gas formations and saline formations; assess the storage potential for two additional geologic formations; conduct terrestrial sequestration pilot projects in Lake County, Oregon, and Shasta County, California; and convey results through a variety of means such as public meetings, conference papers, and the web. States involved include California, Oregon, Washington, Alaska, Nevada, the western portion of Arizona, and British Columbia. The project is led by the California Energy Commission. For more information, visit http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase2/pdf/westcarb.pdf.

1.3.4 Regional Partnerships Deployment Phase Activities

The DOE is working with the Regional Partnerships to conduct large volume (between 100,000 and 1,000,000 tons per year of CO_2) sequestration tests. A large volume of CO_2 would be injected during several years of injection operations into a geologic formation which is representative of a relatively large storage capacity for the region. The amount of CO_2 injected would depend on the cost and availability of CO_2 in the region. These large volume sequestration test activities would last for 10 years and be divided into three budget periods. The following is an example of the activities that will occur during these budget periods. The duration of these budget periods may vary.

- Budget Period 1 – Site selection, characterization, NEPA compliance, permitting and infrastructure development.
- Budget Period 2 – Injection and monitoring activities.
- Budget Period 3 – Site closure, post injection monitoring and analysis.

1.3.5 Integration - FutureGen

FutureGen, the Integrated Sequestration and Hydrogen Research Initiative, is a $1 billion government/industry partnership to design, build, and operate a nearly emission-free, coal-fired electric and hydrogen production plant. The prototype plant will serve as a large-scale engineering laboratory for testing new clean power, carbon capture, and coal-to-hydrogen technologies. It is intended to be the cleanest fossil fuel-fired power plant in the world. Virtually every aspect of the prototype plant will employ cutting-edge technology. With respect to sequestration technologies, captured CO_2 will be separated from the hydrogen perhaps by novel membranes currently under development. It would then be permanently sequestered in a deep saline formation. A Draft EIS for the FutureGen Project was published in May 2007.

1.3.6 Program Goals

The principal goal of the Carbon Sequestration Program is to gain a scientific understanding of carbon sequestration options and to provide cost-effective, environmentally-sound technology options that ultimately may lead to a reduction in GHG intensity and stabilization of atmospheric concentrations of CO_2. The Program is at the forefront of the Nation's efforts to address the problem of GHG emissions and is an integral part of plans to develop large-scale fossil fuel conversion processes with near-zero GHG emissions. Overarching goals of the Program are presented in Table 1-1 with component-specific goals being presented in Table 1-2. The primary Carbon Sequestration Program Goal is to develop fossil fuel conversion systems that offer 90 percent CO_2 capture with 99 percent storage permanence at less than 10 percent increase in the cost of energy services.

Table 1-1. Overarching Program Goals

Year	Goal
2007	Identify capture technologies that increase the cost of energy services by less than 20 percent for pre-combustion systems and less than 45 percent for post-combustion systems and oxy-combustion systems.
2008	Develop Monitoring, Mitigation and Verification (MM&V) protocols that enable 95 percent of stored CO_2 to be credited as net emissions reduction.
2009	Complete validation phase of Regional Carbon Sequestration Partnership Program.
2011	Initiate at least one large-scale demonstration of CO_2 storage (1 million tons CO_2/year) in a geologic formation.
2012	Develop MM&V protocols that enable 99 percent of CO_2 to be credited as net emissions reduction.
2014	Initiate at least two slipstream tests of novel CO_2 capture technologies that offer significant cost reductions.
2015	Develop terrestrial sequestration technologies to the point of commercialization at a cost not exceeding $5/metric ton of carbon sequestered.
2016	Begin at least one demonstration in which CO_2 is stored in a saline formation and brine water from the saline formation is recovered for beneficial use.

Source: NETL, 2007.

In addition to the component-specific goals and through the Regional Partnerships, DOE established the several objectives. These objectives are consistent with the overarching goals of the Program and include initiating seven cost-share projects that were to be completed in 2004, issuing awards for Phase II technology validation (awarded 2006), and conducting numerous small-scale field validation tests to be completed between 2006 and 2013. Lastly, in the pursuit of breakthrough concepts, DOE collaborated with the National Academy of Science (NAS) in 2003, which conducted a workshop to identify R&D opportunities for breakthrough concepts advancing carbon sequestration. DOE used the results of the workshop to develop a solicitation for R&D projects that were selected by the Program. When proposals were received, a NAS committee evaluated the scientific, technical, engineering, and environmental merits of each. Through this collaborative effort, DOE established the following objectives:

- Award multiple R&D projects (completed in 2004);
- Demonstrate, potentially, 2 projects at the laboratory scale (by 2007); and
- Assess at least one GCCI technology breakthrough concept (by 2012).

Table 1-2. Component-Specific Goals

Program Component	Goals	Pathways	Metrics for Success	
			2007	**2012**
CO_2 Capture	Lower the capital cost and energy penalty associated with capturing CO_2 from large point sources.	Membranes Advanced Scrubbers CO_2 Hydrates Oxy-fuel Combustion	50% reduction in cost of avoided CO_2 emissions from power plants compared to 2002 technology (based on pilot-scale performance)	Develop at least two capture technologies that each result in less than a 10% increase in cost of energy services.
Sequestration /Storage	Improve understanding of factors affecting CO_2 storage performance and capacity in geologic formations, terrestrial ecosystems and possibly the deep oceans. Develop field practices to optimize CO_2 storage.	Hydrocarbon bearing geologic formations Saline formations Tree plantings, silvicultural practices and soil reclamation Increased ocean uptake	Field tests provide improved understanding of the factors affecting permanence and capacity in a broad range of CO_2 storage formations.	Demonstrate ability to predict CO_2 storage capacity with +/- 30% accuracy. Demonstrate enhanced CO_2 trapping at pre-commercial scale.
Monitoring, Mitigation & Verification	Develop technologies and methodologies to accurately measure the amount of CO_2 stored in terrestrial ecosystems and geologic formations. Develop the capability to address any leaks of the stored CO_2 from various repositories.	Advanced soil carbon measurement Remote sensing of above-ground CO_2 storage and leaks Detection and measurement of CO_2 in geologic formations Fate and transport models for CO_2 in geologic formations	Demonstrate advanced CO_2 measurement and detection technologies at sequestration field tests and commercial deployments.	MM&V protocols that enable 95% of stored CO_2 to be credited as net emissions reduction. MM&V represents no more than 10% of the total sequestration system cost.
Breakthrough Concepts	Develop revolutionary approaches to CO_2 capture and storage that have the potential to address the level of reductions in greenhouse gas emissions consistent with long term atmospheric stabilization.	Advanced CO_2 capture Advanced subsurface technologies Advanced geochemical sequestration Novel niches	Laboratory scale results from 1-2 of the current breakthrough concepts show promise to reach the goal of a 10% or less increase in the cost of energy, and are advanced to the pilot scale.	Technology from the program's portfolio revolutionaized the possibilities for CO_2 capture, storage, or conversion.
Non-CO_2 GHGs	Develop technologies to mitigate fugitive methane from energy systems.	Minemouth ventilation Landfill gas recovery	Effective deployment of cost-effective methane capture systems.	Commercial deployment of at least two technologies from the R&D program.
Infrastructure Development	Develop the infrastructure required for wide scale deployment of sequestration concepts that are tailored to opportunities within specific regions of the U.S. and involve citizens, companies, and governments from those areas.	Sequestration atlases Project implementation plans Regulatory compliance Outreach and education	Regional Partnerships have developed action plans and completed regional atlases. Partnerships begin pursuing action plans and validation of sequestration concepts.	Regional Partnerships start to become self-sustaining and begin to actively pursue sequestration deployments.

2.0 PROGRAM TECHNOLOGIES AND STATE APPLICABILITY

2.1 INTRODUCTION

This chapter provides detailed descriptions of leading technologies and associated R&D projects planned and anticipated under the Carbon Sequestration Program. This chapter also summarizes the current results of ongoing efforts to characterize existing CO_2 sources and potential repositories (sinks) and it describes the applicability of leading technologies by state.

Finally, the chapter presents a series of model projects that are representative of the leading technologies anticipated for field or pilot tests and potential implementation during future phases of the Program. The model projects consist of hypothetical facilities that would be necessary to implement the objectives of each respective project, including assumptions about land requirements, process components, supporting facilities, and construction aspects. To the extent practicable, the hypothetical projects have been conceived as sufficiently generic to be located in any region of the country. However, it is expected that the process demands and waste streams of respective model projects will create challenges that may affect their future siting.

Detailed model project descriptions are provided for those technologies that are in further stages of development. These would be more likely to be included in the pilot field validation testing of the Phase II Program, and potentially commercially deployed in the future at a much larger scale. Information summarized for each of the technologies in a model project includes general design and operating parameters of the project, environmental aspects, utility requirements, site requirements and operations, and construction requirements.

Model projects have been developed for:

- post-combustion CO_2 capture;
- CO_2 compression and transport;
- geologic sequestration options, including coal seam, basalt formation, enhanced oil recovery (EOR), and saline formation;
- co-sequestration of CO_2 and hydrogen sulfide (H_2S) in both Integrated Gasification Combined Cycle (IGCC) power plant and sour associated gas production cases; and
- reforestation of formerly mined lands.

Although not a DOE-NETL research area, a CO_2 compression and transport model project was developed to characterize all potential impacts of carbon sequestration from sources to sinks.

For other DOE-NETL technologies that are still in the early stages of R&D, detailed model project characterizations were not prepared. For those technologies, brief technology description summaries are presented in Appendix B. These R&D technologies include pre-combustion decarbonization, oxyfuel combustion, sequestration in other geologic formations, ocean sequestration (which is no longer investigated by the Program), breakthrough concepts, and co-sequestration of CO_2 with nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from pulverized coal boilers. Also, a model project was not developed for agricultural terrestrial sequestration, as the USDA primarily leads that area of technology development.

2.2 PROGRAM TECHNOLOGY DESCRIPTIONS

DOE-NETL's core R&D efforts are focused in five key areas:

- CO_2 Capture
- Sequestration
- Monitoring, Mitigation, and Verification (MM&V)
- Breakthrough Concepts
- Non-CO_2 Greenhouse Gas (GHG) Mitigation

The portfolio of R&D efforts has two primary objectives: (1) lowering the cost and energy penalty associated with CO_2 capture from large point sources; and (2) improving the understanding of factors affecting CO_2 storage permanence and capacity in geologic formations, terrestrial ecosystems, and oceans. For both objectives, research is aimed at broadening the potential implementation of sequestration technology beyond early niche opportunities.

Figure 2-1 illustrates the relationships among these technologies and a relative timeline for their implementation.

2.2.1 Post-Combustion CO_2 Capture

Post-combustion capture involves the removal of CO_2 from the flue gas produced from fossil-fueled power plants, such as coal-fired or natural gas fuel. The key technical issues with this approach are that flue gas is usually near atmospheric pressure, and the CO_2 concentration is low (Klara and Srivastava, 2002). Flue gas from a pulverized coal-fired (PC) boiler is exhausted at 10-15 psi and contains 12-18 percent CO_2 by volume. The low partial pressure of CO_2 results in only a small driving force for traditional adsorption/absorption processes. While post-combustion CO_2 capture may not have the greatest potential for step-change reductions in separation and capture costs, it has the greatest near-term potential for reducing emissions. This is because post-combustion processes can be retrofitted to existing facilities, and the U.S. has 300 gigawatts (GW) of PC boiler capacity (NETL, 2005b).

2.2.1.1 Advanced Amine Absorption

The conventional technology for post-combustion CO_2 capture is amine scrubbing, in which a solution of amine and water is contacted with flue gas in a contactor unit. The amine and the CO_2 undergo a chemical reaction forming a CO_2-rich amine that is soluble in water. The CO_2-rich amine solution is then pumped to a regenerator where it is heated. This reverses the chemical reaction and releases pure CO_2 gas. The recovered amine is then recycled to the flue gas contactor. Both primary and secondary amines are used in CO_2 capture processes. Monoethanolamine (MEA), considered to be the state-of-the-art technology, gives fast rates of absorption and favorable equilibrium characteristics. Secondary amines, such as diethanolamine (DEA), also exhibit favorable absorption (NETL, 2004c).

A major problem associated with amine absorption is the degradation of the solvent through irreversible side reactions with SO_2 and other flue gas components resulting in solvent loss (Klara and Srivastava, 2002). In high concentrations, MEA is corrosive and is therefore typically diluted with water in these absorption systems. Due to the presence of the water, the amine solution requires significant energy for regeneration and also delivers CO_2 at low pressure. Significant R&D work is needed on membrane contactors to improve chemical compatibility with alkanolamines and high-temperature resistance. Researchers have an opportunity to optimize existing solvents or develop new solvents and system components to reduce total capital and operating costs.

Advanced solvents will be prepared by chemical treatment of high surface oxide materials with various amine compounds. Tasks include the modification of oxidized solid surfaces, chemical characterization of the amine-enriched sorbents, determination of CO_2 capture capacity, and examination of the performance durability of amine-enriched adsorbents. R&D tasks are also needed to optimize chemical scrubbing processes for CO_2 separation, develop improved gas-liquid mass transfer, develop improved amine absorbent systems that require less thermal energy for regeneration, increase the loading of the absorbent within the aqueous amine solution, and reduce the content of water in the amine solution (NETL, 2004a and 2004b).

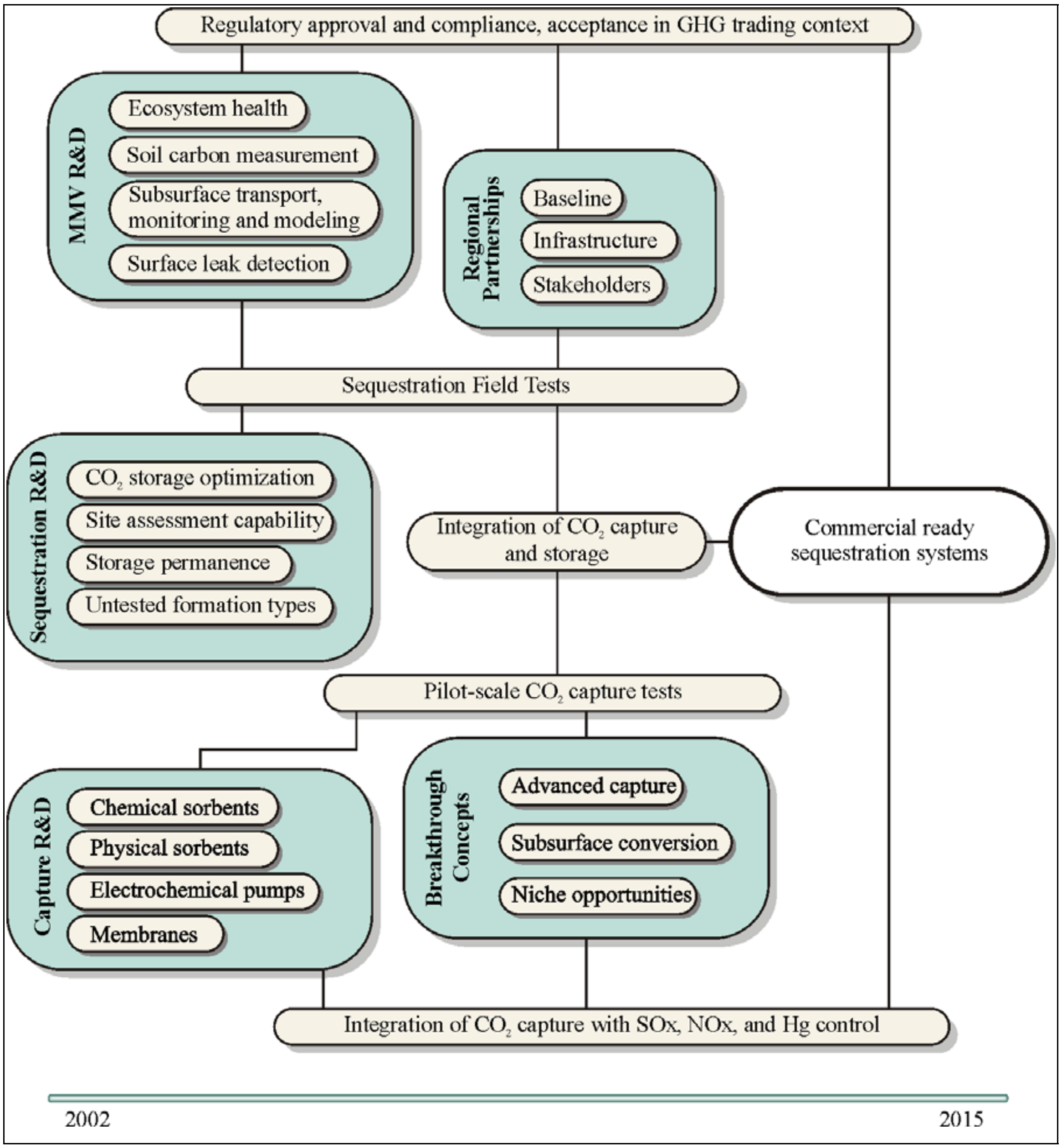


Figure 2-1. Carbon Sequestration Program Technologies and Timeline

2.2.2 Sequestration

Sequestration encompasses all forms of carbon storage, including storage in geologic formations and terrestrial ecosystems. Geologic sequestration is the placement of CO_2 or other greenhouse gases into subsurface porous and permeable rocks in such a way that they remain permanently stored. Terrestrial sequestration relies on natural processes in plants and microorganisms that take up CO_2 and convert the carbon into vegetative biomass or minerals.

2.2.2.1 Geologic Sequestration Overview

Geologic storage of anthropogenic (man-made) CO_2 as a GHG mitigation option was first proposed in the 1970s, but little research was done until the early 1990s. In a little over a decade, geologic storage of CO_2 has grown from a concept of limited interest to one that is quite widely regarded as a potentially important mitigation option. Technologies that have been developed for and applied by the oil and gas industry can be used for the injection of CO_2 in deep geologic formations. Well-drilling technology, injection technology, computer simulation of reservoir dynamics, and monitoring methods can potentially be adapted from existing applications to meet the needs of geologic storage (IPCC, 2005).

Types of geologic formations capable of storing CO_2 include oil and gas bearing formations, saline formations, basalts, deep coal seams, and oil- or gas-rich shales. Not all geologic formations are suitable for CO_2 storage; some are too shallow and others have low permeability (the ability of rock to transmit fluids through pore spaces) or poor confining characteristics. Formations suitable for CO_2 storage have specific characteristics such as thick accumulations of sediments or rock layers, permeable layers saturated with saline water (saline formations), extensive covers of low porosity sediments or rocks acting as seals, (caprock), structural simplicity, and lack of faults (IPCC, 2005). Figure 2-2 illustrates sequestration within a saline formation.

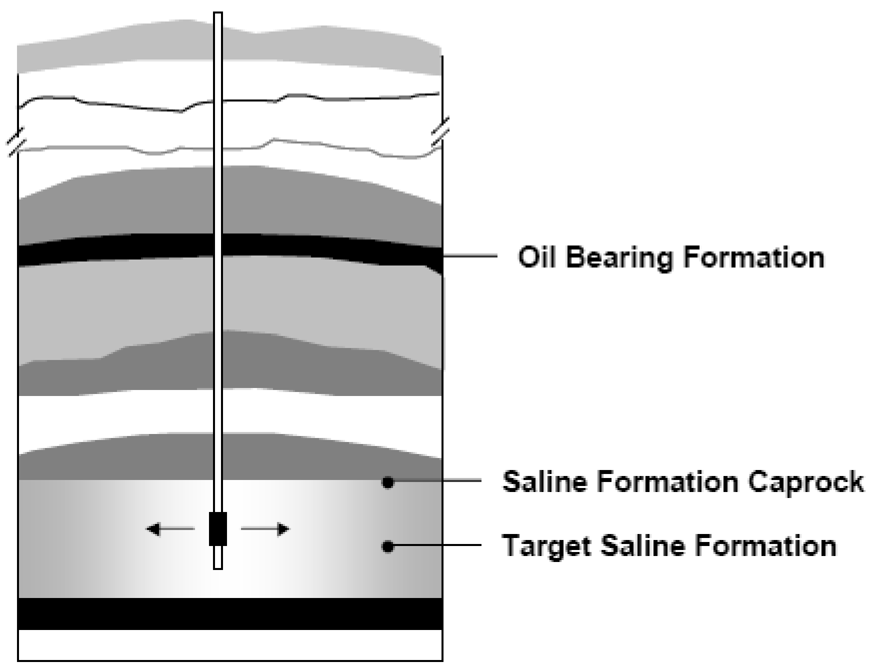


Figure 2-2. Geologic Sequestration Example - Deep Saline Formation

Supercritical CO_2 - CO_2 usually behaves as a gas in air or as a solid in dry ice. If the temperature and pressure are both increased (above its supercritical temperature of 88ºF [31.1ºC] and 73 atmospheres [1,073 psi]), it can adopt properties midway between a gas and a liquid, such that it expands to fill its container like a gas, but has a density like that of a liquid.

The CO_2 would be compressed into a supercritical state and injected into a deep geologic formation. The injected CO_2 would displace the existing water occupying the formation's pore space. Without this displacement, CO_2 could only be injected by increasing the formation's fluid pressure, which could result in formation fracturing. If a formation's fluid pressure is too high, the sequestration process may require installation of extraction wells that remove water from the formation.

To increase the storage potential, CO_2 would be injected into very deep formations where it could maintain its dense supercritical state. The fate and transport of CO_2 in the formation would be influenced by the injection pressure, dissolution in the formation water, and upward migration due to CO_2's buoyancy.

Injection would raise the fluid pressure near the well allowing CO_2 to enter the pore spaces initially occupied by the saline water within the formation. Once injected, the spread of CO_2 would be governed by the following primary flow, transport and trapping mechanisms:

- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow (migration) in response to natural groundwater flow;
- Buoyancy caused by the density differences between CO_2 and the groundwater;
- Diffusion;
- Dispersion and fingering (localized channeling) caused by formation heterogeneities and mobility contrast between CO_2 and the groundwater;
- Dissolution into the formation groundwater or brine;
- Mineralization;
- Pore space trapping; and
- Adsorption of CO_2 onto organic material.

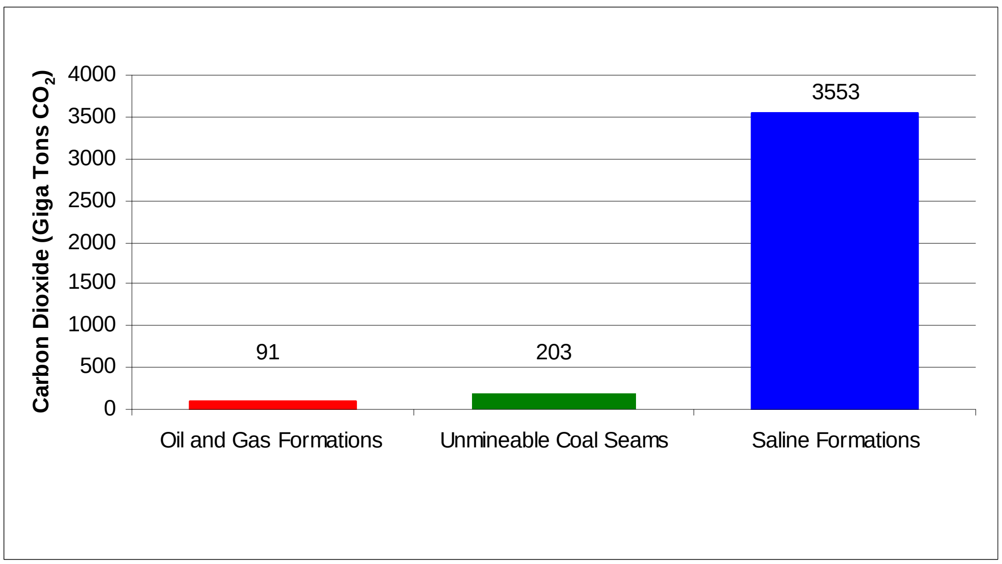
The magnitude of the buoyancy forces that drive vertical flow depends on the type of fluid in the formation. When CO_2 is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is only somewhat miscible in water. Because supercritical CO_2 is much less viscous than water (by an order of magnitude or more), it would be more mobile and could migrate at a faster rate than the saline groundwater. In saline formations, the comparatively large density difference (30 to 50 percent) creates strong buoyancy forces that could drive CO_2 upwards.

To provide secure storage (e.g., structural trapping), a lower permeability layer (caprock) would act as a barrier and cause the buoyant CO_2 to spread laterally, filling any stratigraphic or structural trap it encounters. As CO_2 migrates through the formation, it would slowly dissolve in the formation water. In systems with slowly flowing water, reservoir-scale numerical simulations show that, over tens of years, up to 30 percent of the injected CO_2 would dissolve in formation water. Larger basin-scale simulations suggest that, over centuries, the entire CO_2 plume would dissolve in formation water. Once CO_2 is dissolved in the formation water, it would no longer exist as a separate phase (thereby eliminating the buoyant forces that drive it upwards), and it would be expected to migrate along with the regional groundwater flow.

As migration through a formation occurs, some of the CO_2 would likely be retained in the pore space, commonly referred to as "residual CO_2 trapping." Residual trapping could immobilize large amounts of the CO_2. While this effect is formation-specific, researchers estimate that 15 to 25 percent of injected CO_2 could be trapped in pore spaces, although over time much of the trapped CO_2 dissolves in the formation water (referred to as “dissolution trapping”). The dissolved CO_2 would make the formation water more acidic, with pH dropping as low as 3.5, which would be expected to dissolve some mineral grains and mineral cements in the rock, accompanied by a rise in the pH. At that point, some fraction of the CO_2 may be converted to stable carbonate minerals (mineral trapping), the most permanent form of geologic storage. Mineral trapping is believed to be comparatively slow, taking hundreds or thousands of years to occur (IPCC, 2005).

To ensure the safe storage of sequestered CO_2, a monitoring and mitigation strategy would be implemented. The purposes of monitoring include assessing the integrity of plugged or abandoned wells in the region; calibrating and confirming performance assessment models; establishing baseline parameters for the storage site to ensure that CO_2-induced changes are recognized; detecting microseismicity associated with the storage project; measuring surface fluxes of CO_2; and designing and monitoring remediation activities.

Figure 2-3 illustrates the relative capacity of various geologic sequestration approaches. Through the development of optimized field practices and technologies, the Program seeks to quantify and improve the storage capacity of all potential formations (NETL, 2005b).



Source: NETL, 2007.

Figure 2-3. Carbon Dioxide Capacity Estimates for the U.S. and Canada of Areas Assessed by the Carbon Sequestration Regional Partnerships

2.2.2.2 Sequestration in Unmineable Coal Seams

> With their large internal surface areas, coal seams can store several times more CO_2 than the equivalent volume of a conventional gas formation.

An attractive option for disposal of CO_2 is geologic sequestration in deep, unmineable coal seams. Coalbed methane (CBM) recovery is the fastest growing source of domestic natural gas supply and accounted for 8 percent of domestic production in 2002. Enhanced CBM (ECBM) recovery is usually achieved by flooding the coal seam with nitrogen. Because CO_2 preferentially adsorbs onto the surface of coal and releases methane, it offers an attractive alternative to nitrogen. With their large internal surface areas, coal seams can store several times more CO_2 than the equivalent volume of a conventional gas formation. These formations have high potential for adsorbing CO_2 on coal surfaces, and the displaced methane offers a valuable byproduct to reduce the overall cost of sequestration. The maximum capacity for CO_2 ECBM in the U.S. has been estimated at 90 billion metric tons of CO_2, but 44 percent of this capacity is in Alaska. The ultimate commercial deployment of ECBM carbon sequestration may depend in part on the availability of surface and mineral rights, future mining technology developments and coal prices, and CO_2 injectivity rates.

One problem with CO_2 ECBM is the tendency for coal to swell in volume as it adsorbs CO_2, which restricts the flow of CO_2 into the formation and impedes methane recovery (NETL, 2004a).

Several R&D projects and large-scale field tests are currently underway to investigate sequestration mechanisms in coal seams.

2.2.2.3 Sequestration in Depleted Oil and Gas Reserves

> The CO_2 storage capacity of domestic oil and gas fields could potentially sequester 30 years worth of U.S. emissions.

Approximately 32 million tons per year of CO_2 are injected into depleting oil formations in the U.S. as part of EOR operations. The typical storage rate is 2,000 scf CO_2 per barrel oil recovered, but current practices are not directed toward optimizing CO_2 storage (NETL, 2005a). The CO_2 storage capacity of domestic oil and gas fields has been estimated at approximately 150 billion metric tons of CO_2, which represents 30 years worth of U.S. emissions (NETL, 2004a). It is not yet possible to predict storage volumes, formation integrity, and permanence with confidence over long periods of time. Many important issues must be addressed, such as interactions between CO_2 and formation rock and other fluids, as well as the monitoring and verification of fluids (including CO_2) in underground oil and gas fields. Large-scale demonstrations are needed to confirm practical considerations, such as economics, safety, stability, permanence and public acceptance (Klara, et. al., 2003).

Early tests involve sequestration experiments in which collateral benefits are likely, such as storing CO_2 in depleted oil and gas fields, where additional hydrocarbons may be produced. Because such formations are generally gas tight (i.e., where leakage of natural gas and other associated gases is negligible), the risk of leakage is expected to be minimal. These geologic traps by their very nature, having confined accumulations of oil and natural gas over millions of years, have proven their ability to contain fluids and gas. Additionally, if storage pressures of CO_2 stay below original formation pressures and there is integrity of existing well bores, there should be no leakage (IOGCC, 2005).

These geologic structures that originally contained the oil and natural gas should be able to permanently sequester the injected CO_2, provided the integrity of the structure is maintained. Because of seismic studies, the geologic structure and physical properties of many oil and gas fields are well understood. For example, one commercial CO_2 EOR operation in the U.S. began in 1986, and leakage of CO_2 via well bores or through the formation cap is considered to be negligible, and monitoring wells are used to track movement of injectant within the formation (NETL, 2004d). Also, monitoring of the Weyburn commercial scale CO_2 EOR project (see description in 3.3.5.2) which utilizes observation wells, 3D seismic, cross-well seismic, soil monitors, and gas tracers, soil sampling indicates no CO_2 leakage from the formation and there is no independent evidence to suggest any significant volume of CO_2 has migrated above the formation (NETL, 2005).

These long term geologic storage issues, such as leakage of CO_2 through old well bores, faults, seals, or diffusion out of the formation, need to be addressed. Many tools exist or are being developed for monitoring geologic sequestration of CO_2, including well testing and pressure monitoring; tracers and chemical sampling; surface and bore hole seismic; and electromagnetic/geomechanical meters. However, the spatial and temporal resolution of these methods may not be sufficient for performance confirmation and leak detection. Therefore, further monitoring needs include:

- High resolution mapping techniques for tracking migration of sequestered CO_2
- Deformation and microseismicity monitoring
- Remote sensing for CO_2 leaks and land surface deformation (Klara, et al., 2003)

More details on geologic sequestration MM&V technologies are presented in Section 2.2.3.

The potential for enhanced oil and gas production helps mitigate sequestration costs. Most EOR projects in the U.S. are in the Permian Basin of Texas, and most of the CO_2 used is transported by pipeline from natural CO_2 formations in Colorado, New Mexico, and Wyoming. It is anticipated that recovery of CO_2 from flue gas of coal burning power plants could be profitable for regional EOR use (Klara, et al., 2003).

2.2.2.4 Sequestration in Saline Formations

Deep saline formations are among the largest and most widely available potential formations for long-term CO_2 storage. About two-thirds of the U.S. is underlain by deep saline formations.

Saline formations are layers of porous rock that are saturated with brine, or highly saline water (NETL, 2004a). Deep saline formations are among the largest and most widely available potential formations for long-term CO_2 storage. About two-thirds of the U.S. is underlain by deep saline formations (Bergman and Winter, 1995), and usable formations are known to exist under the oceans. These formations have an estimated CO_2 adsorption capacity of between 320 billion and 10 trillion tons. Moreover, many of these formations are located in close proximity to major point sources of CO_2 emissions, such as fossil-fuel power plants, which offers the benefit of reducing costs for transportation of CO_2 to the injection site (NETL, 2002). Because the brine water from such formations is typically not suitable for irrigation and other uses, injection of CO_2 and its subsequent aqueous dissolution does not affect the potential use of the water. However, there are many uncertainties associated with the reactions that may occur between CO_2, brine, and minerals in the surrounding strata (Klara, et al., 2003). (Note: Brine is defined as water containing more dissolved inorganic salt than typical seawater, or greater than 35,000 ppm total dissolved salts [TDS], as compared to fresh water containing less than 1000-2000 ppm TDS [Schlumberger, 2005 and USGS, 2003]. Varying grades of saline water have salt concentrations between those two levels. Within this document, the terms brine formation and saline formation are used synonymously, and imply the presence of either brine [>35,000 ppm TDS] and/or highly saline water [10,000-35,000 ppm TDS]).

Two key issues distinguish CO_2 sequestration in saline formations from sequestration in oil and gas fields. First, oil and gas fields result from the presence of a structural or stratigraphic trap. This same trap is likely to retain CO_2 as well. Identification of such effective traps may be more difficult in aqueous formations and may require new approaches for establishing the integrity and extent of a caprock. Second, injection of CO_2 into a saline formation is unlikely to be accompanied by removal of water from the formation. In the case of EOR, oil and brine are simultaneously withdrawn while CO_2 is injected. Injection of CO_2 into a saline formation, on the other hand, will lead to an increase in formation pressure over a large area. Whether, and to what extent, large-scale pressurization will affect caprock integrity, cause land surface deformation, and induce seismic hazards, must be better understood to design safe and effective sequestration in saline formations. Another issue pertains to the acceptable leakage rate from the formation into overlying strata (DOE, 1999). Furthermore, sequestration in a saline formation does not offer the value-added benefit of enhanced hydrocarbon production. The structural and stratigraphic traps of oil and gas fields should contain the CO_2 injected as part of an EOR project, so long as pathways to the surface or to adjacent formations are not created by over-pressuring the formation, by fracturing out of the formation at wells, or by

Leakage of injected CO_2 from a deep saline formation into overlying formations is a relevant concern, particularly where drinking water sources are in the vicinity.

leaks around wells and through abandoned well bores. Although EOR has the benefit of sequestering CO_2 while increasing production from active oil fields, and its technology for CO_2 injection is commercially proven, in the long term the volume of CO_2 sequestered as part of the EOR phase of those sequestration projects may not be large (DOE, 1999). Once the EOR/sequestration project's oil fields are fully depleted over time, their long term CO_2 injection and storage concerns will be similar to those of saline formations.

Injection into a deep saline formation and potential leakage into overlying formations is a relevant concern, particularly where drinking water sources are in the vicinity. Most studies to date have been concerned with breaching the caprock, formation capacity and injectivity, and CO_2, water and host/seal rock interaction. Less work has been done to understand the effects of displacing the saline water from the deeper basin into shallower outcrops, subcrops, or into freshwater regions of the same formation. Injection is not purely displacement due to the dissolution of CO_2 into water, i.e., a unit volume of CO_2 does not necessarily displace a unit volume of water. Depending on the dissolution time and CO_2 solubility of the water, only a fraction of the water is displaced. The outer perimeter of a basin is extremely large compared to a single injection well, or a field of injection wells; therefore, the change in position of a freshwater/saline water interface is likely very small.

Recent analytical estimations using pressure transient analysis indicate only very small pressure (<1 psi) changes occur 30-40 miles away from a single well after 30 years of injecting 1 MMT CO_2/year; additionally, no appreciable change in velocity or interface location was predicted for 100 years of 300 million metric tons (MMT) CO_2/year (approximately the entire Illinois Basin's current stationary source CO_2 emissions). These preliminary simulations show that the injection of large volumes of CO_2 in a saline formation has an inconsequential effect on the position of the fresh-salt water interface after decades of continuous injection (Frailey, et al., 2005).

2.2.2.5 Sequestration in Basalt Formations

Basalt is a hard, black volcanic rock and is the most common rock type in the Earth's crust (outer 10 to 50 kilometers). Most of the ocean floor is made of basalt. Large areas of lava called "flood basalts" are found on many continents. For example, the Columbia River basalts erupted 15 to 17 million years ago and cover most of southeastern Washington and regions of Oregon and Idaho.

Major basalt formation may be attractive for carbon sequestration in the Pacific Northwest, the Midwest, the Southeastern U.S. and several other locations. Basalt formations have unique properties that can chemically trap injected CO_2, effectively and permanently isolating it from the atmosphere (NETL, 2004a).

2.2.2.6 Co-Sequestration of CO_2 and H_2S

Natural gas processing from sour gas fields results in a CO_2 waste stream laden with H_2S. This acid gas is injected into deep saline formations and depleted oil or natural gas formations at 41 locations in Canada, and at approximately 20 sites in Michigan, New Mexico, Oklahoma, Texas, and Wyoming in the U.S. In Canada, a total of 2.5 million tons of CO_2 and 2 million tons of H_2S have been injected through the end of 2003. Co-sequestration of these gases is appropriate for EOR operations or geologic sequestration in saline formations. In addition, IGCC power generation technology, which produces a combined CO_2/H_2S emission stream, provides substantial environmental benefits as opposed to conventional coal burning power technology. To incorporate IGCC technology and support program application to sour gas processing, two model project cases of co-sequestration capture of CO_2 and H_2S have been developed: (1) IGCC power plant; and (2) sour associated gas production.

2.2.2.7 Terrestrial Sequestration

Terrestrial sequestration relies on natural processes in plants and microorganisms to take up CO_2 and convert the carbon into vegetative biomass or minerals.

Terrestrial ecosystems, which include both soil and vegetation, are widely recognized as a major biological “scrubber” for CO_2. Terrestrial sequestration is defined as either the net removal of CO_2 from the atmosphere or the prevention of CO_2 emissions from leaving terrestrial ecosystems.

Terrestrial carbon sequestration can be enhanced in four ways:

- reversing land use patterns;
- reducing the decomposition of organic matter;
- increasing the photosynthetic carbon fixation of trees and other vegetation; and
- creating energy offsets using biomass for fuels and other products.

The terrestrial biosphere is estimated to sequester large amounts of carbon, about 2 billion tons annually. The total amount of carbon stored in soils and vegetation throughout the world is estimated to be roughly 2,000 billion tons (NETL, 2003).

Because the U.S. has vast agricultural and forest resources, policymakers have looked to terrestrial sequestration as an option for reducing net GHG emissions from stationary sources and vehicles. Numerous tree-planting projects have been undertaken by industry, and scientists are experimenting with agricultural practices that enhance carbon storage in soils. In the near-term, sequestration of carbon in terrestrial ecosystems offers a low-cost means of reducing CO_2 in the atmosphere with significant ancillary benefits, including restored natural environments for plants and wildlife, reduced runoff, and increased domestic production of agriculture and forest products (NETL, 2005a).

Currently, terrestrial uptake offsets roughly one third of global anthropogenic CO_2 emissions. The uptake from domestic terrestrial ecosystems is expected to decrease 13 percent over the next 20 years as northeastern forests mature. Opportunities for enhanced terrestrial sequestration include 1.5 million acres of land damaged by past mining practices, 32 million acres of Conservation Reserve Program (CRP) farmland, and 120 million acres of pastureland (NETL, 2005b).

DOE’s core R&D program currently is limited to the integration of energy production, conversion, and use with land reclamation (NETL, 2005b). Specifically, this involves reforestation and the amendment of damaged soils using solid residuals from coal combustion where possible. The Program's activities are closely coordinated with efforts undertaken by the USDA, the U.S. Forestry Service, the Office of Surface Mining, and the DOE Office of Science, Center for Enhancing Carbon Sequestration in Terrestrial Ecosystems (CSiTE). NETL is participating in OSRME's Appalachian Regional Reforestation Initiative which is designed to promote the Forestry Reclamation Approach (FRA) on abandoned and recently mined lands. This FRA is being applied in several of NETL's core R&D projects.

2.2.3 Monitoring, Mitigation, and Verification (MM&V)

MM&V is defined as the capability to:

- measure the amount of CO_2 stored at a specific sequestration site;
- monitor the site and mitigate the potential for leaks or other deterioration of storage integrity over time; and
- verify that the CO_2 is being stored and is not harmful to the host ecosystem (NETL, 2005b).

Reliable, affordable and practical methods of MM&V are needed for projects to sequester carbon in underground storage sites, and in forests and soils.

Monitoring is likely to be required as part of the permitting process for underground injection and would be used for a number of purposes, including but not limited to:

- tracking the location of the plume of injected CO_2;
- ensuring that injection and abandoned wells are not leaking; and
- for verification of the quantity of CO_2 that has been injected.

Additionally, depending on site-specific conditions, monitoring may also be required to ensure that natural resources such as groundwater and ecosystems are protected and that local populations are not exposed to unsafe concentrations of CO_2 (Benson, 2002).

MM&V can be divided into three broad categories: subsurface, soils, and aboveground (NETL, 2004a). Subsurface MM&V involves tracking the fate of the CO_2 within the geologic formations underlying the earth and possible migration or leakage to the surface. Soils MM&V involves tracking carbon uptake and storage in the first several feet of topsoil and tracking potential leakage pathways into the atmosphere from the underlying geologic formation. This area of research is especially challenging due to the difficulty in detecting small changes in CO_2 concentration above background concentration emissions (~370 parts per million (ppm)) that already exist in the atmosphere. Aboveground MM&V is specific to terrestrial sequestration and involves quantification of the aboveground carbon stored in vegetation.

MM&V includes the development of protocols and methodologies for calculating the net avoided CO_2 emissions from systems associated with carbon capture, transport, and storage, while specifically considering and comparing different levels of parasitic losses in generating capacity (to provide power for the added processes) and methods for replacing capacity. Current MM&V practices are time-consuming and costly, and this situation is further complicated by the fact that standard, acceptable protocols for carbon measurement and accounting do not exist. Advanced technologies for higher resolution CO_2 detection are being tested at several sites, including the Sleipner, Weyburn, and West Pearl Queen formations. Effective MM&V technologies will be essential for the success of a potential future carbon emissions credit trading market. As an example of the future potential for such a market, Ontario Power Generation bought 6 million tons of CO_2 emissions credits from Blue Source LLC in July 2002. Blue Source provided the emission reductions from oil field carbon sequestration projects in Texas, Wyoming, and Mississippi (NETL, 2005b).

2.2.3.1 Geologic Sequestration MM&V

Subsurface MM&V systems draw upon the significant capabilities developed for fossil resource exploration and production over the past century. Work in subsurface MM&V options includes surface-to-borehole seismic, micro-seismic, and cross-well electromagnetic imaging devices to characterize storage formation properties and changes after CO_2 injection. Aboveground MM&V technology is less mature and is focused on detecting leaks or deterioration in the storage formation and assessing ecological impacts of geologic carbon storage (NETL, 2005b).

> As seismic imaging can have an adverse impact on biological resources, potential impacts and mitigation measures are discussed in Section 4.4 "Biological Resources".

Monitoring methods will depend on the type of geologic sequestration being performed and the geologic conditions of the project area. For example, depleted oil and gas fields are particularly suitable for CO_2 storage as they have been shown by the test of time that they can effectively store buoyant fluids, such as oil, gas and CO_2 (Benson, 2002). Storage in deep saline formations is in principle the same as storage in oil or gas fields, but the geologic seals that would keep the CO_2 from rising rapidly to the ground surface need to be characterized and demonstrated to be suitable for long-term storage (Benson, 2002). Coal beds offer the potential for a different type of storage where CO_2 becomes chemically bound to the solid coal matrix. Over hundreds to thousands of years, some fraction, including possibly all of the CO_2, is expected to dissolve in the formation fluids. Once dissolved or reacted to form minerals, CO_2 is no longer buoyant and consequently, would no longer rise rapidly to the ground surface in the absence of s suitable geologic seal (Benson, 2002).

Approaches for monitoring geologic storage of CO_2 are provided in Table 2-1.

Table 2-1. Monitoring Approaches for Geologic Sequestration of CO_2

Parameter	Monitoring Approaches
CO_2 plume location	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Electrical and electromagnetic methods* *Land surface deformation using satellite imaging or tiltmeters* *Gravity methods* *Formation pressure monitoring* *Wellhead and formation fluid sampling* *Natural and introduced tracers*
Providing early warning that a storage site may be failing	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Land surface deformation using satellite imaging or tiltmeters* *Injection well and formation pressure monitoring*
CO_2 concentrations and fluxes at the ground surface	*Real-time IR based detectors for CO_2 concentrations* *Air sampling and analysis using gas chromatography or mass spectrometry* *Eddy flux towers* *Monitoring for natural and introduced tracers*
Injection well condition, flow rates and pressures	*Borehole logs, including casing integrity logs, noise logs, temperature logs, and radiotracer logs* *Wellhead and formation pressure gauges* *Wellbore annulus pressure measurements* *Orifice or other differential flow meters* *Surface CO_2 concentrations near the injection wells*
Solubility and mineral trapping	*Formation fluid sampling using wellhead or downhole samples - analysis of CO_2, major ion chemistry and isotopes* *Monitoring for natural and introduced tracers, including partioning tracers*
Leakage up faults and fractures	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Electrical and electromagnetic methods* *Land surface deformation using satellite imaging or tiltmeters* *Formation and aquifer pressure monitoring* *Groundwater and vadose zone sampling*
Groundwater quality	*Groundwater sampling and geochemical analysis from drinking water or monitoring wells* *Natural and introduced tracers*
CO_2 concentrations in the vadose zone and soil	*Soil gas surveys and gas composition analysis* *Vadose zone sampling wells and gas composition analysis*
Ecosystem impacts	*Hyperspectral geobotanical monitoring* *Soil gas surveys* *Direct observation of biota*
Micro-seismicity	*Passive seismic monitoring using single or multi-component seismometers*

Source: Benson, 2002.

Although there are no model projects developed for MM&V methods, seismic imaging can have adverse impacts on biological resources. The potential impacts associated with seismic imaging and possible mitigation measures will be discussed in Section 4.5 “Biological Resources”.

2.2.3.2 Terrestrial Sequestration MM&V

Methods for monitoring and verifying the amount of carbon stored in terrestrial ecosystems are slow and imprecise. Because terrestrial sequestration relies on natural processes, public health and safety issues are not driving the need for MM&V. However, precise and reliable measurements of both aboveground carbon and soil carbon will be needed to enable the use of terrestrial sequestration in emissions trading applications. Roughly 8 MMT of carbon sequestered in terrestrial ecosystems was traded in 2002, requiring preliminary estimations of baseline carbon stocks and projected storage. Methods for modeling and tracking aboveground carbon, such as 3D videography, correlations between soil and aboveground carbon, and infield technology to measure soil and other below-ground carbon will reduce the cost of establishing a baseline for carbon stocks. Current on-the-ground measurements are accurate within plus or minus 5 to 30 percent, and can cost as little as $1 per ton net carbon offset (NETL, 2005b).

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2.3 CARBON DIOXIDE SOURCES AND SINKS

2.3.1 CO_2 Sources

Most U.S. anthropogenic CO_2 emissions result from the combustion of fossil fuels by power plants, industrial facilities, vehicles, and residential and commercial heating systems. Industrial sources of relatively pure CO_2 emissions are natural gas processing, ammonia production, and ethanol production. Another large source of CO_2 emissions is the calcination of limestone in cement production. Other sources include lime manufacture, limestone and dolomite consumption, soda ash manufacture and consumption, industrial CO_2 manufacture, and aluminum production. For the purposes of identifying CO_2 sources, this section focuses on and provides information about fossil-fueled power plants, natural gas processing, ammonia production, ethanol production, and cement production.

2.3.1.1 Fossil-Fueled Electric Plants

Based on the DOE Energy Information Administration's "Inventory of Electric Utility Power Plants in the U.S, 2000", there were 6,099 fossil fuel based electric plants in the U.S. in 2000 (EIA, 2000). These plants had a generation capability of over 430,000 mega-watts (MW) of electricity. In 2003, CO_2 emissions associated with electric utility plants equaled 2,408.9 MMT (EIA, 2003a). The top 10 states for the highest number of coal, gas or petroleum based electric power plants are (in descending order): Alabama, Kansas, Iowa, Texas, Florida, Missouri, Michigan, Ohio, Minnesota and Nebraska (see Table 2-2).

Table 2-2. Fossil-Fueled Electric Plants, Top 10 States (2000)[1]

State	Number of Fossil Fueled Electric Plants	Planned Additions (2001-2005)[2]
Alaska	509	15
Kansas	418	24
Iowa	400	25
Texas	375	withheld
Florida	335	25
Missouri	328	15
Michigan	326	withheld
Ohio	272	18
Minnesota	269	24
Nebraska	244	14

1 EIA reports available after 2000 provide data in terms of geographic regions that and does not provide data in terms of individual states.
2 Data provided on planned additional plants do not specify fuel type.

Source: EIA, 2000.

Although the number of electric power generating plants can be a good estimate of CO_2 capture and sequestration potential, the overall amount of CO_2 emissions from all energy sources within the states is also a good overall indicator of future sequestration potential. The DOE Energy Information Administration’s (EIA) 1989-2004 Estimated Emissions by State and Fuel Type report was reviewed to determine total CO_2 emissions from power plants at the state level. The data is presented as the total CO_2 emissions for Electric Utilities per state and the emissions for all sectors and all sources (i.e. coal, natural gas, petroleum, others) (see Table 2-3). Ohio leads the nation for CO_2 emissions from Electric Utilities generation, followed by Florida, Indiana, Texas and Kentucky. The state with the highest CO_2 emissions from all sources is Texas followed by Florida, Ohio, Pennsylvania and Indiana (EIA, 2005b).

Table 2-3. CO_2 Emissions in 2004 by State from Electric Utility Plants and All Sectors

State	Electric Utility (Million Metric Tons)	All Sources (Metric Tons)
Alabama	73.2	80.2
Alaska	2.9	4.7
Arizona	41.5	50.6
Arkansas	25.1	27.1
California	6.0	60.7
Colorado	35.6	39.6
Connecticut	0.0	10.3
Delaware	0.0	6.5
District of Columbia	0.1	0.0
Florida	114.4	130.1
Georgia	74.4	81.5
Hawaii	5.6	8.9
Idaho	0.0	1.3
Illinois	19.1	100.3
Indiana	109.0	118.9
Iowa	35.7	40.0
Kansas	37.2	37.3
Kentucky	75.1	87.3
Louisiana	24.2	58.1
Maine	0.0	7.0
Maryland	0.0	31.8
Massachusetts	1.0	26.1
Michigan	65.3	77.2
Minnesota	32.9	37.6
Mississippi	19.1	25.3
Missouri	74.5	75.9
Montana	0.4	19.1
Nebraska	20.6	20.7
Nevada	20.0	25.3
New Hampshire	5.5	8.2
New Jersey	1.9	21.3
New Mexico	30.6	30.9
New York	13.2	57.6
North Carolina	65.7	72.6
North Dakota	30.0	30.4
Ohio	116.9	123.1
Oklahoma	39.0	46.6
Oregon	4.4	9.1
Pennsylvania	17.4	121.6
Rhode Island	0.0	2.1
South Carolina	36.8	39.4
South Dakota	3.8	3.8
Tennessee	52.4	58.5
Texas	77.7	255.7
Utah	34.1	35.2
Vermont	0.0	0.0
Virginia	30.5	46.8
Washington	1.0	15.0
West Virginia	53.6	82.2
Wisconsin	43.9	49.4
Wyoming	43.3	45.5

Source: EPA, 2005b.

Since states vary greatly in terms of population, the relative CO_2 emissions on a per capita basis may provide a better idea of which states have the highest carbon intensity. Although some states export power to other states, normalizing CO_2 based on state population can be a useful, if not an entirely precise, measure of a state's relative CO_2 output.

The top ten states with the highest CO_2 emissions per capita based on the EIA 2005 Estimated Emissions by State and Fuel Type report and 2000 U.S. Census data are (in descending order): Wyoming, North Dakota, West Virginia, Kentucky and Indiana (see Table 2-4).

Table 2-4. CO_2 Emissions per Capita (from Electricity Production and All Sources)

State	Electric Utility (Metric Tons)	All Sources (Metric Tons)
Alabama	16.5	18.0
Alaska	4.7	7.5
Arizona	8.1	9.9
Arkansas	9.4	10.1
California	0.2	1.8
Colorado	8.3	9.2
Connecticut	0.0	3.0
Delaware	0.0	8.3
District of Columbia	0.1	0.0
Florida	7.2	8.1
Georgia	9.1	10.0
Hawaii	4.6	7.4
Idaho	0.0	1.0
Illinois	1.5	8.1
Indiana	17.9	19.6
Iowa	12.2	13.7
Kansas	13.9	13.9
Kentucky	18.6	21.6
Louisiana	5.4	13.0
Maine	0.0	5.5
Maryland	0.0	6.0
Massachusetts	0.2	4.1
Michigan	6.6	7.8
Minnesota	6.7	7.6
Mississippi	6.7	8.9
Missouri	13.3	13.6
Montana	0.5	21.2
Nebraska	12.0	12.1
Nevada	10.0	12.7
New Hampshire	4.5	6.6
New Jersey	0.2	2.5
New Mexico	16.8	17.0
New York	0.7	3.0
North Carolina	8.2	9.0
North Dakota	46.6	47.3
Ohio	10.3	10.8
Oklahoma	11.3	13.5
Oregon	1.3	2.7
Pennsylvania	1.4	9.9
Rhode Island	0.0	2.0
South Carolina	9.2	9.8
South Dakota	5.1	5.1

State	Electric Utility (Metric Tons)	All Sources (Metric Tons)
Tennessee	9.2	10.3
Texas	3.7	12.3
Utah	15.3	15.7
Vermont	0.0	0.0
Virginia	4.3	6.6
Washington	0.2	2.5
West Virginia	29.7	45.4
Wisconsin	8.2	9.2
Wyoming	87.6	92.0

Source: EPA, 2005b, U.S. Census 2005.

2.3.1.2 Natural Gas Processing Plants

CO_2 is produced as a byproduct of natural gas production and processing. Natural gas produced from natural gas wells (referred to as non-associated natural gas) and natural gas produced from crude oil wells (referred to as associated-dissolved natural gas) may contain naturally occurring CO_2 that must be removed from the natural gas in order for it to meet pipeline specifications for CO_2 content. A fraction of the CO_2 remains in the natural gas delivered to end-users by pipeline, and is emitted when the natural gas is combusted. However, the majority of the CO_2 is separated from natural gas at gas processing plants. CO_2 removed at gas processing plants is generally vented to the atmosphere. However, capture and sequestration of CO_2 from natural gas processing plants is already occurring in Wyoming and Texas. As of 2002, there were four gas processing plants that produce CO_2 for use in enhanced oil recovery (EPA, 2004).

In 2004, 17,993,520 million cubic feet of natural gas was processed in the U.S. About half the natural gas processing in the U.S. occurs in Texas, Wyoming and Oklahoma (EIA, 2005c). The top 10 states for natural gas processing are (in descending order of production): Texas, Wyoming, Oklahoma, New Mexico, Louisiana, Colorado, Kansas, Alabama, Utah and Michigan (see Table 2-5) (EIA, 2005c).

Table 2-5. Top Ten States for Natural Gas Processing in 2004

State	Million Cubic Feet
Texas	5,074,067
Wyoming	1,736,136
Oklahoma	1,604,709
New Mexico	1,397,934
Louisiana	1,293,204
Colorado	1,002,453
Kansas	350,413
Alabama	333,583
Utah	259,432
Michigan	212,276

Source: EIA, 2005c.

2.3.1.3 Ammonia Plants

Anhydrous ammonia is produced by the refinement of natural gas in the presence of steam and injected with air. A typical ammonia plant uses approximately 32,000 cubic feet of natural gas to produce one ton of ammonia (NH_3). After desulphurization of the gas, steam is induced to the process gas and passed through a catalyst in a heated reformer. Air is then injected, and the gas is sent through 2 separate catalyst beds for CO conversion. The gas is then sent through a CO_2 absorber, then on to methanation, and then compressed to 4,000 to 4,600 psi (GVC, 2005).

The U.S. produces approximately 13 percent of the global production of anhydrous ammonia. In 2002, 19 companies operated 44 ammonia production plants with a combined capacity of over 15 million metric tons of anhydrous ammonia (TIG, 2002). Over half of the production capacity was centered in Louisiana (10 plants), Oklahoma (5 plants), and Texas (5 plants) due to large reserves of natural gas. Iowa and Kansas have three ammonia plants each; California and Mississippi have two ammonia plants each; and the following states have one ammonia plant each: Alaska, Florida, North Dakota, Wyoming, Oregon, Nebraska, Virginia, Idaho, Alabama, Georgia, Ohio, Tennessee, Illinois and Arkansas. Plants in these states may be good candidates for carbon sequestration projects, because CO_2 is a byproduct of ammonia production.

2.3.1.4 Ethanol Plants

Ethanol is part of an alcohol-based alternative fuel produced by fermenting and distilling starch crops that have been converted into simple sugars. Feedstocks for this fuel include corn, barley, and wheat. Ethanol is most commonly used to increase octane and improve the emissions quality of gasoline. Ethanol can be blended with gasoline to create E85, a blend of 85 percent ethanol and 15 percent gasoline. Vehicles that run on E85 are called flexible fuel vehicles. Looking into the future, the ethanol industry envisions a time when ethanol may be used as a fuel to produce hydrogen for fuel cell vehicle applications.

CO_2 is a main byproduct of the fermentation associated with ethanol production, making ethanol plants good candidates for carbon sequestration projects. According to the Renewable Fuels Association, there are 99 ethanol plants in 19 states within the U.S. that have the capacity to produce nearly 4.9 billion gallons annually. There are also 46 ethanol plants either under new construction or have major expansions under construction with a combined capacity of an additional three billion gallons. Most ethanol plants are located in the Midwest due to the abundant supply of corn and other starch crops. The states with the most ethanol plants are Iowa, Minnesota, South Dakota and Nebraska (see Table 2-6). Ethanol production also occurs in Kansas, Illinois, Indiana, Wisconsin, Colorado, North Dakota, California, Michigan, Missouri, Kentucky, Ohio, Georgia, New Mexico, Tennessee, and Wyoming. Plants are also planned for Texas, Arizona, and Oregon (RFA, 2006).

Table 2-6. Ethanol Producing Facilities in the U.S.

State	Current Facilities	Planned New Facilities or Expansions	Total Current and Future Facilities
Iowa	24	7	31
Nebraska	10	10	20
Minnesota	16	1	17
South Dakota	11	3	14
Kansas	7	2	9
Illinois	6	1	7
Indiana	1	5	6
Wisconsin	5	1	6
Colorado	3	2	5
North Dakota	2	3	5
California	3	1	4
Michigan	1	3	4
Missouri	3	1	4
Texas	0	3	3
Kentucky	2	0	2
Ohio	1	1	2

State	Current Facilities	Planned New Facilities or Expansions	Total Current and Future Facilities
Arizona	0	1	1
Georgia	1	0	1
New Mexico	1	0	1
Oregon	0	1	1
Tennessee	1	0	1
Wyoming	1	0	1
Total	99	46	145

Source: RFA, 2006.

2.3.1.5 Cement Production Facilities

Cement production, while not the largest source of industrial CO_2 emissions, is probably the most intensive source. The Portland Cement Manufacturers Association pledged in February 2003 to adopt a goal of reducing CO_2 emissions per ton of product by 10 percent (from 1990 levels) by the year 2020 (PCA, 2003). Although their plan does not specifically rely on carbon sequestration, it is likely that cement manufacturers would utilize capture/sequestration as a means to meet their reduction goals. The national weighted average carbon intensity (metric tons CO_2 per metric ton of cement produced) was estimated at 0.97 tons CO_2/ton cement in 2001 (Hanle, 2004). The states with the highest total production of cement are (in decreasing order): California, Texas, Pennsylvania, Michigan, Missouri, Alabama, and Florida (see Table 2-7).

Table 2-7. States with the Most Annual Cement Production

State	Millions of Metric Tons
California	11.68
Texas	10.90
Pennsylvania	6.47
Michigan	6.20
Missouri	5.11
Alabama	4.93
Florida	4.80

Note: Data is 2003, except where data was withheld - then the latest year reported was used. Cement production occurs in 37 states, however, USGS data on their website does not reflect mineral production in all 37 states.

Source: USGS, 2003.

2.3.1.6 Sources of Sour Gas (CO_2 with H_2S)

Gas streams consisting primarily of CO_2 with some H_2S can be derived from two primary sources: IGCC power plants and the processing of oil and gas from fields with high H_2S content (sour gas fields).

Currently, there are two IGCC plants producing commercial electricity in the U.S. (in Indiana and Florida), but more of these types of plants are expected to be constructed in the future as clean air regulations promote this low-emission, coal burning technology.

> Sour Gas is defined as natural gas that contains sulfur, sulfur components and/or CO_2 in quantities that may require removal for effective use (because of its corrosive effect on piping and equipment and its danger to human life).

Although comprehensive data is not available on sour gas fields in the U.S., a report conducted by the Gas Research Institute (GRI) in 1991 - using the best available data from the Bureau of Mines at that time - stated that the areas where natural gas had significant levels of H_2S included North Dakota, Wyoming, Texas, Alabama, and Mississippi, with a few exceptionally high concentrations in Texas, Alabama, Mississippi and Florida (GRI, 1991). The report also concluded that approximately 22 percent of the natural gas produced in the continental U.S. contains H_2S at levels exceeding 4 parts per million by volume (ppmv), the pipeline specification for H_2S. Table 2-8 provides a summary of the data presented in the GRI report by state.

Table 2-8. Maximum H_2S Concentrations in Natural Gas

State	Maximum H_2S Concentration in Natural Gas Reported (Percent by Volume)1
Texas	22.80
Alabama	13.80
Mississippi	10.4
Florida	9.50
Michigan	6.50
North Dakota	4.80
Minnesota	2.90
Arkansas	1.85
Wyoming	1.61

[1] *These data were considered incomplete at the time of publication and the authors noted that concentrations provided may under-represent actual values.*

Source: GRI, 1991.

Sour gas injection into deep saline formations and depleted oil or natural gas fields is already occurring at 41 locations in Albert and British Columbia in Canada and at approximately 20 sites in Michigan, New Mexico, Oklahoma, Texas and Wyoming in the U.S (IOGCC, 2005). Therefore, there may be additional sites within these states that would be candidates for co-sequestration of CO_2 and H_2S.

2.3.2 CO_2 Sinks

2.3.2.1 Coal Seams

What constitutes an unmineable coal seam is not clearly defined, and can be further complicated by expected advances in mining technology. Thus, coal seams that run deeper than can be economically mined today may be candidates for mining in the future as technology advances. Consequently, regional applicability is discussed based on the Coal Demonstrated Reserve Base, underground coal data (EIA, 1997). Regions with coal deposits are shown in Chapter 3, Figures 3-15 to 3-17. Data on coal reserves by state is provided in Table 2-9.

Table 2-9. U.S. Coal Demonstrated Reserve Base (1997)

State	Underground Coal (Billion Short Tons)
Illinois	88.1
Montana	71.0
Wyoming	42.5
West Virginia	29.7
Pennsylvania	23.5
Ohio	17.6
Kentucky	17.5
Colorado	11.7
Indiana	8.8
New Mexico	6.2
Alaska	5.4
Utah	5.3
Iowa	1.7

State	Underground Coal (Billion Short Tons)
Missouri	1.5
Washington	1.3
Oklahoma	1.2
Virginia	1.2
Alabama	1.1
North Dakota	0.0
Texas	0.0
Other	1.5
U.S. Total	336.8

Source: EIA, 1997.

Based on these coal reserve data, Illinois and Montana may have the highest potential for coal seam carbon sequestration projects due to their vast underground coal resources. The top ten states with the largest underground coal reserves are (in descending order) are: Illinois, Montana, Wyoming, West Virginia, Pennsylvania, Ohio, Kentucky, Colorado, Indiana and New Mexico.

2.3.2.1.1 Coalbed Methane (CBM)

Carbon sequestration projects are more likely to occur in areas where a primary or secondary economic benefit can be obtained. As CO_2 injection enhances recovery of CBM, CO_2 sequestration projects may be biased towards areas where CBM reserves are known to exist. Conservative estimates suggest that in the U.S. more than 700 trillion cubic feet (Tcf) of CBM exist in place, of which perhaps 100 Tcf are economically recoverable with existing technology, which is the equivalent of about a 5-year supply at present rates of use (USGS, 2001).

The largest known concentration (56 percent) of CBM in the U.S. is in the Rocky Mountains of Wyoming, Utah, New Mexico, Colorado, and Montana. Large deposits of CBM are found and are being developed in the Powder River Basin (northeastern Wyoming and south-central/southeastern Montana), San Juan Basin (northwestern New Mexico), Uinta Basin (northeastern Utah), Piceance Basin (northwestern Colorado), and Raton Basin (southeastern Colorado and northeastern New Mexico). The USGS estimates than approximately 50 Tcf of coalbed methane is extractable in these basins using current technology. Coalbeds that have been strip-mined near the ground surface have lost or "leaked" their coalbed methane over the period of the strip mine activity. Coalbeds that have not been strip-mined, are too deep for strip-mining, or too thinly spaced for surface or underground mining often have recoverable coalbed methane. The Powder River Basin is an excellent example of both: 1) major quantities of coalbed methane recoverable from land proposed for strip mines in the future; and 2) lands with coalbeds thinly present and too deep for economic coal extraction (DOI, 2003). Areas of coalbed methane are shown in Chapter 3, Figure 3-22.

2.3.2.2 Oil and Gas Fields

Oil and gas fields are good candidates for sequestration of CO_2 and also for co-sequestration of H_2S, as both gases aid the recovery of oil and gas, especially when well production drops significantly.

2.3.2.2.1 Potential Locations for Enhanced Oil Recovery (EOR)

Like coal, oil and gas resources are also found in concentrated areas within the U.S. According to the DOE Energy Information Administration U.S. Crude Oil, Natural Gas and Natural Gas Liquid Reserves 2004 Annual Report, 22 percent of the country's proved oil reserves are located in Texas, 20 percent in Alaska, 19 percent in the Gulf of Mexico (Federal offshore), and 16 percent in California (see Table 2-10). Reserves in other states make up the remaining 23 percent (EIA, 2003b). Proved reserves of crude oil declined by 2 percent in 2004 owing mostly to a large 9 percent decrease in the Gulf of Mexico (EIA, 2003b). Although EOR is used for nearly-depleted oil fields, proved oil reserves were used as an indicator for future EOR potential because national data is not collected on depleted oil fields and because currently producing areas will eventually become depleted and may be candidates for EOR in the future.

Table 2-10. Proved Reserves of Crude Oil by State (On-Shore)

State	Million Barrels, 2003
Texas	4,583
Alaska	4,446
California	3,452
New Mexico	677
Oklahoma	588
Wyoming	517
Louisiana	452
North Dakota	353
Montana	315
Kansas	243
Utah	221
Colorado	217
Mississippi	169
Illinois	125
Michigan	75
Florida	68
Ohio	66
Alabama	52
Arkansas	50
Kentucky	25
Indiana	19
Nebraska	16
Pennsylvania	13
West Virginia	13
Other (Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia)	16
Total	16,771

Source: EIA, 2003b.

EOR with CO_2 injection was first tried in 1972 in Scurry County, Texas. Since then, CO_2 injection has been used successfully throughout the Permian Basin of West Texas and eastern New Mexico (where about half of all the CO_2 floods in the world are located), as well as in Louisiana, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania (DOE, 2004). According to a 2002 EOR survey, there were a total of 67 EOR projects in the U.S., 49 of these in the Permian Basin area of West Texas and southeast New Mexico (Moritis, 2002). The Permian Basin is located in West Texas and the adjoining area of southeastern New Mexico. It underlies an area approximately 250 miles wide and 300 miles long and includes the Texas counties of Andrews, Borden, Crane, Dawson, Ector, Gaines, Glasscock, Howard, Loving, Martin, Midland, Pecos, Reeves, Terrell, Upton, Ward, and Winkler. Analyst estimates for the Permian Basin indicate that more than 50 additional projects -adding 500 million to 1 billion barrels of oil reserves- are economically viable at recent prices and current technology. One operator in the Permian Basin planned to initiate 4 to 5 new projects in a 5-year period, in addition to 10 to 12 expansions of existing projects (Moritis, 2001).

DOE is sponsoring a CO_2 injection project (Hall-Gurney Project) into a Lansing-Kansas City formation that was first developed in the 1930s and 1940s. This formation has already been subject to very thorough primary and secondary production. Other possible fields in Kansas that could benefit from CO_2 injection are those that tap the Arbuckle and Morrow Formations of central Kansas.

Additional candidates for CO_2 injection include the Rangely Field in Colorado, the Lost Soldier, Wertz, Salt Creek, Lance Creek, and Mush Creek Fields in Wyoming, numerous other oil fields in Wyoming's Oregon and Elk Basins, and the Bell Creek Field in Montana (Goerold, 2002).

In Mississippi, the Jackson Dome CO_2 source is being used for EOR recovery in the Little Creek field. The operator of the Little Creek field claimed in 2001, "…as much as 1 billion barrels of incremental oil might be recovered through the use of CO_2 flooding"(OGJ, 2001).

Yet another prominent example of CO_2 oil recovery is seen in the San Joaquin Basin of California. Because of poor formation characteristics such as poor permeability, poorly-developed fractures, and a complex geology, oil fields in this southern California basin have produced only about 6.5 percent of the oil, out of an estimated 2.6 billion barrels of oil in place (OGJ, 2000).

DOE has concluded that CO_2 EOR can be utilized to recover "stranded" resources that have been or will be left behind after the use of traditional oil recovery methods. As shown in Table 2-11, EOR could be used to recover nearly 89 billion barrels of oil in assessed oil reserves in many regions of the country, which would be left behind if only traditional recovery methods were used.

Table 2-11. CO_2 EOR Technically Recoverable Resource Potential

Basin/Area	Number of Large Formations Assessed	All Formations (Ten Basins/Areas assessed)		
		Original Oil in Place (billion barrels)	Remaining Oil in Place (billion barrels)	Technically Recoverable (billion barrels)
Alaska	34	67.3	45.0	12.4
California	172	83.3	57.3	5.2
Gulf Coast	239	44.4	27.5	6.9
Mid-Continent	222	89.6	65.6	11.8
Illinois and Michigan	154	17.8	11.5	1.5
Permian (West Texas and New Mexico)	207	95.4	61.7	20.8
Rocky Mountains	162	33.6	22.6	4.2
Texas (east and central)	199	109.0	73.6	17.3
Williston	93	13.2	9.4	2.7
Louisiana Offshore	99	28.1	15.7	5.9
Total	1,581	581.7	390.0	88.7

2.3.2.2.2 <u>Potential Locations for Sequestration in Natural Gas Formations</u>

CO_2 can also be sequestered in depleted natural gas fields. The largest natural gas fields in the U.S. are in Texas, Wyoming, Oklahoma, New Mexico, Louisiana, and Colorado (see Table 2-12). Total U.S natural gas withdrawal in 200 was over 14 trillion c.f. Due to the vast natural gas fields in these states, they may contain the best potential natural gas field sites for carbon sequestration projects. Other states producing natural gas (greater than 10 billion cubic feet a year) are: Kansas, Alabama, Utah, Alaska, Michigan, West Virginia, Pennsylvania, Arkansas, Mississippi, California, Ohio, Kentucky, Virginia, Montana, New York, and North Dakota (EIA, 2005a). These states also have potential for future carbon sequestration projects.

Table 2-12. Natural Gas Withdrawals from Gas Wells, 2003

State	Natural Gas Withdrawals (Million Cubic Feet)
Texas	4,947,589
Wyoming	1,652,504
Oklahoma	1,487,451
New Mexico	1,391,916
Louisiana	1,283,513

State	Natural Gas Withdrawals (Million Cubic Feet)
Colorado	970,229
Kansas	369,624
Alabama	365,330
Utah	254,488
Alaska	196,989
Michigan	194,121
West Virginia	187,723
Pennsylvania	159,827
Arkansas	157,039
Mississippi	156,727
California	90,368
Ohio	87,993
Kentucky	87,608
Virginia	81,086
Montana	78,175
New York	35,943
North Dakota	14,524
Indiana	1,464
Nebraska	1,187
Oregon	731
South Dakota	550
Arizona	443
Illinois	169
Maryland	48

Source: EIA, 2005a.

2.3.2.2.3 Saline Formations

Saline formations are good sinks for CO_2 and also for co-sequestration of CO_2 and H_2S. One of the goals of DOE's Carbon Sequestration Program is to continue to assess potential saline formations that are suitable for sequestering CO_2.

In a 2003 study funded by DOE/NETL, the Bureau of Economic Geology (BEG) at the University of Texas at Austin inventoried 16 geologic characteristics of 21 brine-bearing formations in the continental U.S. to provide basic data needed to assess the feasibility, costs, and risks of this sequestration method (BEG, 2003). These 21 formations covered an area of 4.3 million square kilometers (1.66 million square miles) or roughly 56 percent of the contiguous U.S.. While BEG acknowledged that many other formations may be suitable for field studies at a pilot scale or for sequestering output of individual emitters, their study focused on formations with the potential to scale up to store large volumes of CO_2.

BEG selected only one formation as a target in most areas, so the results are not comprehensive, nor should they be considered a capacity assessment. The study did however characterize many of the major, regionally extensive saline formations to improve the chance of matching as many sites as possible. One of the most favorable units that BEG assessed is the Frio Formation of the Gulf Cost, with 300 m of sand over wide areas and 28 to 35 percent porosity.

A map of deep saline formations within the U.S. is provided in Chapter 3, Figure 3-24. Additionally, saline formations undergoing study by the Regional Partnerships are presented in Figure 3-25. The data from this map is comprised of GIS data from the individual Regional Partnerships. Some Partnerships are still developing their GIS database and therefore saline formations in some regions are not fully represented by this figure.

2.3.2.3 Basalt Formations

Another option for geologic sequestration is basalt formations. Basalt is a hard, black volcanic rock and is the most common rock type in the Earth's crust (outer 10 to 50 kilometers). Most of the ocean floor is made of basalt. Large areas of lava called "flood basalts" are found on many continents. For example, the Columbia River basalts erupted 15 to 17 million years ago and cover most of southeastern Washington and regions of Oregon and Idaho (USGS, 2005).

Major basalt formation may be attractive for carbon sequestration in the Pacific Northwest, the Midwest, the Southeastern U.S. and several other locations. Basalt formations have unique properties that can chemically trap injected CO_2, effectively and permanently isolating it from the atmosphere (NETL, 2004).

"Preliminary experiments conducted at Pacific Northwest National Laboratory (PNNL) have confirmed that carbonate mineral formation occurs when basalts from the Columbia River Basalt Group are exposed to supercritical CO_2" (NETL, 2004).

Basalt formations that hold the most promise for carbon sequestration are: Columbia River Basalt Group; Snake River Plain; Keweenawan Rift Basalts; East Continental Rift Zone; Newark Supergroup; Northern California Volcanics; Southern Nevada Volcanics; and Southeast Rift Zone (Figure 3-26).

2.3.2.4 Terrestrial Sequestration

Under DOE's Carbon Sequestration Program, future terrestrial sequestration projects may focus on reclamation and restoration of mined lands and other properties that have been degraded as a consequence of mineral extraction for energy development. Therefore, areas targeted primarily under DOE's Carbon Sequestration Program will consist of former surface mining sites.

The Rural Abandoned Mine Program (RAMP) was authorized by Section 406 of the Surface Mining Control and Reclamation Act (SMCRA) of 1977 as amended by the "Abandoned Mine Reclamation Act of 1991" as subtitled under the Budget Reconciliation Act (Public Law 101-508; 30 U.S.C. 1236). It is authorized for the purpose of reclaiming the soil and water resources of rural lands adversely affected by past coal mining practices. There were approximately 1.1 million acres of abandoned coal-mined land needing reclamation in 1977 (NRCS, 2005).

> Under DOE's Program, terrestrial sequestration projects will focus on reclamation and restoration of formerly mined lands and other properties that have been degraded as a consequence of mineral extraction for energy development.

The total magnitude of the abandoned mine problem is difficult to assess, but OSMRE (Office of Surface Mining Reclamation and Enforcement) has developed a national inventory that contains information on more than 17,700 problem areas associated with abandoned mine lands, mostly coal. A problem area is a geographical area, such as a watershed, that contains one or more problems. The more serious problem areas are classified as priority 1 (extreme danger to public health and safety), priority 2 (adverse affects to public health, safety, and general welfare), or priority 3 (environmental hazards). Since 1977, over 190,000 equivalent acres of priority 1 and 2 health and safety, and environmental-related coal problems have been reclaimed (OSMRE, 2005a).

Querying the OSMRE Abandoned Mine Land Inventory System (AMLIS) for priorities 1, 2, and 3 problem areas, a list of the number of acres or acre-equivalents of land to be restored in each state was generated (OSMRE, 2005b). The results of this query are provided in Table 2-13. Based on these data, the U.S. has an estimated 13,581,700 acres of land designated priority 1, 2, or 3. Using these results, states that may have the most acres available for reforestation or terrestrial sequestration projects on previously mined lands include West Virginia, Virginia, Alabama, Pennsylvania and Oklahoma. This list is not considered a definitive list of available acres that could be reforested, but may be useful as an indicator as to which states may have the most potential for future terrestrial sequestration projects under DOE's program.

Table 2-13. Abandoned Mine Land Problem Areas

State	Abandoned Mine Land Problem Areas (Acres or Acre-Equivalents, Priority 1, 2, 3)
West Virginia	4,997,570
Virginia	2,208,110
Alabama	2,180,250
Pennsylvania	1,687,630
Oklahoma	1,001,830
Missouri	248,200
Kansas	220,380
Ohio	165,190
Kentucky	142,540
Illinois	133,470
Maryland	126,580
Iowa	119,810
North Dakota	112,230
Tennessee	99,660
Arkansas	73,410
Washington	16,000
Alaska	12,870
Indiana	12,840
Wyoming	10,000
Colorado	5,900
Utah	5,800
Georgia	1,430

Source: OSMRE, 2005b.

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2.4 REGIONAL APPLICABILITY

Availability of CO_2 from point sources is not expected to be a limiting factor in carbon sequestration technology deployment. Rather, deployment would be influenced to a greater degree by the presence of suitable geologic resources or, in the case of terrestrial sequestration, availability of appropriate land.

The degree of implementation of carbon sequestration technologies within the U.S. will be influenced by a variety of factors. These factors include availability and proximity of land and geologic resources that provide sinks for CO_2, the number of CO_2 point-sources, air quality regulations and incentive programs at the state and federal level, and the degree to which funding is available.

Although the types and quantities of point source CO_2 could influence commercial deployment rates of sequestration technologies, availability of CO_2 is not expected to be a limiting factor in technology deployment. Rather, future carbon sequestration deployment would be influenced to a greater degree by the presence of suitable geologic resources or, in the case of terrestrial sequestration, availability of appropriate land. In the case of co-sequestration, sources of CO_2/H_2S gas streams would consist primarily of waste streams from IGCC plants, or sour gas oil and gas processing plants. As there are only 2 commercial IGCC plants in the nation, the presence of sour gas from oil and gas processing in each state has been used as an indicator as to future potential for co-sequestration technology in each region.

As in Section 2.3, various indicators have been chosen to provide some relative measure of the applicability of different sequestration technologies within each state. While carbon sequestration R&D projects can occur in most regions due to their relatively limited size and scope, future commercialization will be influenced to a greater degree by the availability of suitable sinks.

2.4.1 Resources in the States

A summary of carbon sequestration technology applicability indicators for each state is provided in Table 2-14.

Overall, the U.S. has vast coal resources that can be utilized for carbon sequestration. As illustrated in Table 2-14, the states with the greatest demonstrated coal reserves include Illinois (88.1 billion short tons), Montana (71.0 billion short tons), Wyoming (42.5 billion short tons), West Virginia (29.7 billion short tons), and Pennsylvania (23.5 billion short tons). Ohio, Kentucky, and Colorado each have substantial reserves with 17.6, 17.5, and 11.7 billion short tons of demonstrated coal reserves respectively. To a lesser degree Indiana, New Mexico, Alaska, and Utah have meaningful coal reserves at 8.8, 6.2, 5.4, and 5.3 billion short tons respectively. Several states have minimal demonstrated resources with less than 2 billion short tons, which include Alabama, Missouri, Oklahoma, Virginia, and Washington. The remaining states have no demonstrated coal reserves.

The U.S. has significant crude oil resources that could be utilized for carbon sequestration through enhanced oil recovery, which are primarily found in the western half of the country. The states with by far the greatest oil reserves are Texas (4,583 million barrels), Alaska (4,446 million barrels), and California (4,251 million barrels). Several states have no oil reserves, which include Georgia, Idaho, Iowa, Maryland, Minnesota, North Carolina, Oregon, South Carolina, Washington, and Wisconsin. The remaining states contribute between 1 and 667 million barrels (see Table 2-14 for details).

The U.S. has considerable potential to utilize depleted natural gas reserves for carbon sequestration, which is evidenced by natural gas production totals. Texas is by far the greatest natural gas producer in the country with 4.9 trillion cubic feet produced a year.

There are many opportunities for saline formation sequestration throughout the vast majority of states. In southeastern Illinois and southwestern Indiana, below oil formations, is a major saline formation, the Mt. Simon Sandstone, which is widely present at depths from 6,000 to 13,000 feet. The geology of the Mt. Simon formation makes it an excellent storage unit and the caprock seal of the Eau Claire Shale has proven its performance as a seal in containing natural gas (Finley et al., 2004). This formation is generally heterogeneous, which will increase the need for detailed formation characterization and the careful placement of CO_2 in this saline formation. The Madison Group, Williston Basin is an elliptical-shaped basin that extends from the northern Great Plains of the U.S. into Canada. The basin occupies most of North Dakota, northwestern South Dakota, eastern Montana, and a part of southern Manitoba and Saskatchewan in Canada. The U.S. part of the basin presents a maximum Phanerozoic thickness of 16,000 ft in North Dakota.

Carbon sequestration projects in basalt formations could be sited in many locales within the U.S. Portions of the Newark Supergroup basalts underlie parts of Pennsylvania, Maryland and Virginia. The East Continent Rift Zone basalts underlie parts of Ohio, Indiana, and Kentucky. The Keweenawan Rift basalts underlie portions of Michigan, north-central Kansas, northern Wisconsin, eastern and southern Minnesota, central Iowa, and eastern Nebraska. Illinois, Indiana, and Kentucky, central Tennessee, and northern Alabama each contain a portion of the East Continental Rift Zone basalts. The Southeast Rift Zone basalts are found within parts of South Carolina, Georgia, northwestern Florida and southeastern Alabama. The Southern Nevada Volcanics underlies parts of Nevada and the Northern California Volcanics underlies parts of California. Two of the most promising basalt formations for carbon sequestration, the Columbia River Basalt Group and the Snake River Plains, underlie parts of the northwest.

Table 2-14. Technology Applicability Indicators and Results for the States

State	Coal Seam Sequestration [Coal Demonstrated Reserve Base, (billion short tons)]	Oil and Gas Reserve Sequestration Indicators		Saline Formation Indicator [Are Suitable Saline Formations Present?]	Basalt Formation Indicator [Are Notable Basalt Formations Present?]	Terrestrial Sequestration Indicator [Abandoned Coal Mine Acres or Acre-Equivalents]	Co-Sequestration Indicator [Is Sour Gas Known to be Present?]
		Enhanced Oil Recovery [Crude Oil Reserves, (millions of barrels)]	Depleted Natural Gas Formations [Natural Gas Production (million c.f./year)]				
Alabama	1.1	52	365,330	yes	Yes	2,180,250	yes
Alaska	5.4	4,446	196,989	Yes		12,870	---
Arizona	--	*	443	Yes	No	---	---
Arkansas	--	50	157,039	Unknown	No	73,410	---
California	--	4,251	90,368	Yes	Yes	---	---
Colorado	11.7	217	970,229	Yes	No	5,900	---
Florida	--	68	0	yes	Yes	---	---
Georgia	--	0	0	yes	Yes	1,430	---
Idaho	--	0	0	No	Yes	---	---
Illinois	88.1	125	169	Yes	Yes	133,470	---
Indiana	8.8	19	1,464	Yes	Yes	---	---
Iowa	0	0	0	Yes	Yes	119,810	---
Kansas	0	243	369,624	Yes	Yes	220,380	---
Kentucky	17.5	25	87,608	Yes	Yes	142,540	---
Louisiana	--	452	1,283,513	yes	No	---	---
Maryland	--	0	48	Yes	Yes	125,580	---
Michigan	--	75	194,121	Yes	Yes	0	yes
Minnesota	0	0	0	Yes	Yes	---	yes
Mississippi	--	169	156,727	yes	No	---	yes
Missouri	1.5	*	0	Yes	No	248,200	---
Montana	71.0	315	78,175	Yes	No	---	---
Nebraska	0	16	1,187	Yes	Yes	---	---
Nevada	--	*	0	Yes	Yes	---	---

State	Coal Seam Sequestration [Coal Demonstrated Reserve Base, (billion short tons)]	Oil and Gas Reserve Sequestration Indicators		Saline Formation Indicator [Are Suitable Saline Formations Present?]	Basalt Formation Indicator [Are Notable Basalt Formations Present?]	Terrestrial Sequestration Indicator [Abandoned Coal Mine Acres or Acre-Equivalents]	Co-Sequestration Indicator [Is Sour Gas Known to be Present?]
		Enhanced Oil Recovery [Crude Oil Reserves, (millions of barrels)]	Depleted Natural Gas Formations [Natural Gas Production (million c.f./year)]				
New Mexico	6.2	667	1,391,916	Yes	No	---	yes
North Carolina	--	0	0	yes	No	---	---
North Dakota	0	353	14,254	Yes	No	112,230	yes
Ohio	17.6	66	87,993	Yes	Yes	165,190	---
Oklahoma	1.2	588	1,487,451	Yes	No	1,001,830	yes
Oregon	--	0	731	Yes	Yes	---	---
Pennsylvania	23.5	13	159,827	Yes	Yes	1,687,630	---
South Carolina	--	0	0	yes	Yes	---	---
South Dakota	--	*	550	Yes	No	---	---
Tennessee	--	*	0	yes	Yes	---	---
Texas	--	4,583	4,947,589	yes	No	---	yes
Utah	5.3	221	254,488	Yes	No	5,800	---
Virginia	1.2	*	81,086	yes	Yes	2,208,250	---
Washington	1.3	0	0	Yes	Yes	16,000	---
West Virginia	29.7	13	187,723	Yes	No	4,997,570	---
Wisconsin	0	0	0	Yes	Yes	---	---
Wyoming	42.5	517	1,652,504	Yes	Yes	10,000	yes

There are ample opportunities for terrestrial sequestration projects on lands containing abandoned coal mines. DOE's Carbon Sequestration Program would focus on terrestrial sequestration projects on formerly coal-mined lands; therefore, states with the greatest amounts of these land cover types would provide the largest amount of land for DOE-sponsored projects. West Virginia has by far the greatest amount of formerly coal-mined lands with nearly 5 million acres. Alabama and Virginia each have approximately 2.2 million acres of these lands. Pennsylvania has about 1.7 million acres and Oklahoma has about 1 million acres. Missouri has over 248,000 acres and Kansas has more than 220,000 acres. Illinois, Iowa, Kentucky, Maryland, North Dakota, and Ohio each contain between 112,000 and 166,000 acres of formerly coal-mined lands. Alaska, Arkansas, Colorado, Georgia, Utah, Washington, and Wyoming each contain between 1,400 and 73,500 acres.

States with natural gas reserves with elevated levels of H_2S (sour gas) could be locations for co-sequestration projects. Sour gas is known to be present in Alabama, Michigan, Minnesota, Mississippi, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming.

2.4.2 Future Commercial Deployment of Carbon Sequestration Technologies

Based on these data by states presented in Section 2.4.1, regional differences can be expected in the levels of future commercial deployment of each technology. Table 2-15 summarizes estimated future deployment levels for each carbon sequestration technology. The levels indicate high, medium, or low opportunity of commercial deployment for each technology based on their geologic features and

> Estimated levels of future commercial deployment for each Regional Partnership reflect each region's geologic features and resources, relative to other regions in the U.S.

resources, and are meant to provide a general comparison of resources.

The levels should be evaluated in the context of each technology. For example, if a region shows a high deployment level for basalt sequestration, this only means it is high relative to other regions across the U.S. It does not necessarily mean that there are more opportunities for basalt sequestration than other types of sequestration within that region.

The estimated deployment levels are provided to assist in the broad understanding the overall potential for future commercial deployment of technologies in these areas and are not indicators relating to the Program's planned level of regional funding or sponsorship of future research activities.

While some geologic formations have been characterized for their suitability for carbon sequestration, much more research still needs to be done to identify and characterize other potentially suitable formations. Therefore, overall, these estimated deployment levels do not reflect results of specific characterizations of geologic formations in these regions. A discussion of the types of investigations typically conducted and the general characteristics of suitable geologic formations is provided in Section 2.4.3.

Table 2-15. Estimated Future Commercial Deployment Levels

Regional Partnership	Coal Seam Sequestration (including ECBM)	Oil and Gas Formations (including EOR)	Sequestration in Saline Formations	Sequestration in Basalt Formations	Terrestrial Sequestration[1]	Co-Sequestration of CO2 and H2S
Midwest	High	Low	High	Medium	High	Medium
Illinois Basin	High	Low	High	Medium	Low	Low
SECARB	Low	High	High	High	High	High
Southwest	Medium	High	High	Low	Medium	High
West Coast	Low	High	High	High	Low	Low
Big Sky	High	Medium	High	High	Low	Low
PCOR	High	Medium	High	Medium	Low	High

[1] Deployment level is based on acreage of abandoned coal mine areas only. Other large areas of land may be suitable for terrestrial sequestration within each Regional Partnership.

2.4.3 Determining Suitable Sinks

A suitable sink for geologic sequestration purposes is an effective formation system, which is generally considered to be highly porous (i.e., with large pore spaces, or void fractions), and highly permeable (i.e., with low resistance to fluid flow within the formation), and overlain by a thick seal. Such a system promotes ease of CO_2 injection, minimization of pressure effects, and high pore space storage capacity. A thick seal is necessary to prevent leakage of CO_2 to overlying formations. While effective injectivity and sufficient storage capacity are important for CO_2 storage, containment is a critical aspect for any storage site to be successful, and to be considered a sink suitable for long-term storage of sequestered CO_2 (Watson and Gibson-Poole, 2005).

Because of the economic value associated with oil and gas formations and coal seams, much formation information is available for those geologic sequestration applications. However, little physical data exist for many saline formations, especially at depths greater than 2500 feet (Myer et al., 2005).

Sinks suitable for geologic sequestration exhibit the following mechanisms for CO_2 storage (NETL, 2005):

- **Caprock trapping**. An impermeable layer of low-porosity rock serves as a barrier against upward migration of CO_2.
- **Pore space trapping**. Through capillary and surface tension forces, droplets of CO_2 become affixed into a rock pore space (primarily for oil and gas formations, and also for saline formations to some extent).
- **Solubility trapping**. Dissolution of CO_2 in saline water, as CO_2 is soluble in brine. For example, at 1900 psi and 30,000 ppm TDS, one gallon of brine holds 0.4 pounds of CO_2 (primarily for saline formations and basalt formations, and also for oil and gas formations to some extent).
- **Mineralization**. Once in solution, CO_2 will react, albeit at a slow rate, with dissolved minerals to form solid mineral carbonates (primarily for high magnesium content basalts, and for saline formations).
- **Adsorption**. Unmineable coal seams offer a unique storage mechanism as CO_2 molecules adsorb onto the surface of the coal. Adsorbed CO_2 exists as a condensed liquid and is immobile so long as the formation pressure is maintained.

One research group characterized coal at depths greater than 1200 feet as being unmineable. At those depths, a minimum coal seam thickness of 1.5 feet was selected for purposes of identification, accommodating perforations, and production from the coal seam. High permeabilities of 50 mD have been an indicator for potential enhanced coal bed methane (ECBM) recovery. CO_2 storage factors for coal seams (i.e., CO_2 versus methane original gas in place [OGIP], and as a fraction of total storage capacity) generally increase with depth. Sequestration opportunities are also classified at depths of 900-1200 feet (with 500-600 psi formation pressures, and permeabilities of 5-20mD); however, at these shallower depths, coal seam thicknesses would need to be less than 3.5 feet, as thicker seams are likely to be mineable. Finally, at depths of less than 500 feet, no sequestration opportunities are indicated at these shallower depths (Anderson et al., 2005). As CO_2 becomes a super-critical fluid at approximately temperatures greater than 90^{o}F and pressures greater than 1100 psi, there is a lower leakage potential at greater depths (and pressures), as CO_2 stays out of the gaseous phase and is less mobile, and there are less fractures in the coal seam from past mining activities (Drobniak et al., 2005).

For EOR CO_2 sequestration opportunities, the following formation parameters are key in determining the suitability of potential sinks (Knepp, et. al., 2005 and Smith, et. al., 2005):

- Depth
- Field area
- Producing interval thickness
- Miscibility (CO_2 dissolved in oil, or in a separate phase) condition
- Depth to miscible/immiscible boundary (as a function of pressure and temperature gradients)
- Original oil in place (OOIP; a function of formation drainage area, thickness, and porosity)
- Saturation of oil/initial formation water saturation
- Porosity and permeability
- Oil viscosity and API gravity (oil density)
- Recovery and storage factors

In one field evaluated, the formation was typically less than 10 feet thick, and was ¼ mile wide and 2 miles long. Based on available well data and formation modeling, it was estimated that an additional 10-15 percent of oil production could be achieved over 25 years using CO_2 injection (above the production that could be achieved from primary recovery and secondary water flooding) (Knepp et al., 2005).

Suitable saline formations would be located at depths similar to suitable coal seams. The following are key parameters for saline formations as potentially suitable sinks for CO_2 storage (Smith et al., 2005):

- Salinity
- CO_2 solubility
- Porosity and permeability
- Thickness
- Area

As discussed previously, the presence of an effective caprock is a critical component to ensuring the successful long-term storage of CO_2. Some of the key caprock properties that help determine the suitability of a potential CO_2 sink include (Statoil, 2005 and Myer et al., 2005):

- Trap type – structural and/or stratigraphic
- Seal thickness
- Permeability
- Capillary entry pressure

Characterization of a formation to determine its potential suitability for long-term CO_2 storage is a relatively complex undertaking. Such a characterization is intended to determine its structure, stratigraphy, and physical properties. It must include an analysis of seismic and borehole data, augmented by rock material (core and cuttings). This formation mapping should include at a minimum:

- Depth to top formation
- Formation thickness
- Formation physical properties (see below)
- Lateral and vertical stratigraphical and hydraulic continuity
- Regular grid of 2D seismic data over entire formation
- High quality 3D seismic volume over the potential injection site and adjacent area
- Borehole data to permit accurate depth conversion of seismic data
- Such geophysical log data should be collected from wells at least as far from the potential injection point as the predicted CO_2 migration within the formation (Statoil, 2005).

Key formation physical properties to be determined in such a characterization include (Statoil, 2005 and Myer et al., 2005):

- Area
- Thickness
- Porosity and permeability
- Rock particle size distribution
- Sand/shale ratio (if applicable)
- Formation fluid
- Initial pressure and temperature
- Formation water salinity
- Pore water analysis/formation-water-CO_2 chemical reactions
- Formation temperature and allowable injection pressure (determine CO_2 density)

2.5 REPRESENTATIVE MODEL PROJECTS, CHARACTERISTICS AND ENVIRONMENTAL ISSUES

2.5.1 Introduction

As indicated previously in Section 2.1, several model projects were defined and analyzed to determine potential environmental impacts of implementing the Carbon Sequestration Program's technologies. Model projects were developed only for those Carbon Sequestration Program technologies that are likely to be deployed by DOE or others at a much larger, commercial-scale within the next 10 years. The technologies for which model projects were developed include the following:

- Post-combustion CO_2 Capture
- CO_2 Compression and Transport
- Coal Seam Sequestration
- Enhanced Oil Recovery Sequestration
- Saline Formation Sequestration
- Basalt Formation Geologic Sequestration
- Reforestation of Mined Lands
- Co-sequestration of CO_2 and H_2S

For each of these model projects, the following elements of the technology's field application were characterized:

General design and operating parameters

- Process flow diagram
- Type, size, and number of major equipment items
- CO_2 captured, transported, or sequestered
- Monitoring, mitigation, and verification (MM&V) approach
- Utility requirements
- Electricity
- Water
- Steam
- Fuel

Environmental process discharge streams

- Air emissions
- Wastewater
- Solid and liquid wastes
- Drilling cuttings

Site requirements and operations

- Land requirements (total and disturbed)
- Access roads
- Pipelines
- Chemical requirements

- Personnel
- Duration

Construction phase activities

- Site clearing
- Construction
- Duration
- Personnel

Detailed model project descriptions are presented in Sections 2.5.3-2.5.10. Summary tables of Model Project environmental parameters are provided in Section 2.5.11.

Detailed model projects were not developed for those DOE-NETL Carbon Sequestration Program technologies that are in their early stages of development. Carbon sequestration technologies that were not considered further include those that are:

- not likely to be deployed at a pilot or commercial scale within the next ten years;
- currently in an experimental stage where detailed process information is currently unavailable; or
- under the primary purview of another Federal agency (e.g., agriculture terrestrial sequestration programs by U.S. Department of Agriculture).

In lieu of detailed model projects, brief technology descriptions of DOE-NETL's R&D activities are presented Appendix B for the following technologies:

- Pre-combustion Decarbonization and Oxyfuel Combustion
- Other Geologic Formations
- Shale
- Mineralization (e.g., serpentine)
- Agricultural Terrestrial Sequestration
- Ocean Sequestration (which is no longer investigated by the Program)
- Co-sequestration of CO_2 and SO_2/NO_X

2.5.2 Existing Geologic Sequestration Projects – Injection Data

There are over 70 commercial-scale CO_2 EOR projects operating in the U.S., with several having experienced CO_2 injection for periods of 20-30 years. CO_2 injection into saline formations has been performed at a commercial scale in three large projects worldwide, with a fourth due to commence operation in the 2006-2008 timeframe (with several of these projects injecting CO_2 under the seabed). Several small, pilot saline formation CO_2 injection projects have also been performed. Coal seam/ECBM applications have only had two large, multi-well pilot demonstrations, with the few other projects being single well, "micro-pilot" tests. Finally, there have been no basalt formation field tests conducted to date in the U.S., with the first pilot validation test planned as part of the Regional Partnerships Phase II testing.

Table 2-16 summarizes the rates of CO_2 injection and number of injection wells for many of the larger CO_2 geologic sequestration projects that have been conducted throughout the world. For comparative purposes, several of the largest commercial CO_2 EOR projects and the small saline formation pilot projects have also been included. Much less information is readily available on the number of monitoring wells, but it is included in the table where identified.

For the four EOR projects shown in Table 2-16, the annual CO_2 injection rates range from approximately 1.5 to 10 million tons CO_2 per year. Maximum daily injection rates ranged from about

4,000 to 28,000 tons CO_2 per day. As the number of CO_2 injection wells range from 57 to 365, CO_2 injection rates of 54 to 75 tons per day per injection well are estimated. Given the extensive commercial experience associated with the CO_2 EOR technology and the desire to minimize environmental and economic impacts associated with drilling new wells, the model project for EOR assumes an average CO_2 injection rate of 75 tons per day per injection well. For a model project nominally sized at injecting a total of 1 million tons CO_2 per year, this results in a maximum value of 36 injection wells. This is the number of CO_2 injection wells used in the EOR geologic sequestration model project in Section 2.5.6.

For the four commercial scale saline formation projects shown in Table 2-16, annual CO_2 injection rates are on the order of about 1 to 3 million tons CO_2 per year. Maximum daily injection rates are approximately 3,000 to 10,000 tons CO_2 per day. With the number of CO_2 injection wells varying from 1 to 7, this results in CO_2 injectivities of approximately 1,400 to 3,700 tons per day per injection well. These values (being roughly 30 to 50 times that of EOR applications) reflect, in part, the extremely high permeability and porosity associated with saline formations compared to oil formations. Because these projects often involve injecting into deeper formations (to inject below all commercial mineral leases and to avoid any underground sources of drinking water), the costs of drilling and operations and maintenance is much greater. Therefore, in the commercial projects to date, which have been all outside the U.S., there have been several reasons to maximize the CO_2 injectivity of each well.

The saline formation model project assumes a maximum number of 7 injection wells (based on the Gorgon project), injecting a nominal total of about 1 million tons CO_2 per year (based on an average of Sleipner and Snohvit). For the minimum, the model project assumes 1 injection well based on the Frio and Nagaoka pilot projects (See Section 2.5.7).

Table 2-16. Geologic Carbon Sequestration Project CO_2 Injection Rates and Wells

Technology Type	Project	CO_2 Injection Annual, tpy	CO_2 Injection Max, tpd	Number of Injection Wells	CO_2 Injection, tpd/well	References
EOR	Weyburn	1,700,000	5,500	85	65	*O&GJ-2004, PTRC-2005*
EOR	Rangely Weber	3,300,000	11,300	209	54	*Stevens-2000, O&GJ-2004*
EOR	SACROC	1,400,000	3,700	57	64	*EPRI-1999, O&GJ-2004*
EOR	Wasson Denver	10,000,000	27,500	365	75	*EPRI-1999, O&GJ-2004*
Saline (On land and sub-seabed)	Gorgon	3,300,000	9,600	7	1,380	*Chevron-2005*
Saline (Sub-seabed)	Sleipner	1,100,000	3,700	1	3,700	*Statoil-2002*
Saline/EGR	In Salah	1,300,000	4,300	3	1,430	*Riddiford-2004*
Saline (Sub-seabed)	Snohvit	800,000	2,900	1	2,900	*Maldal-2004*
Saline	Nagaoka	11,000	44	1	44	*Kikuta-2004*
Saline	Frio	3,000	140	1	140	*Hovorka-2004, Hovorka-2001*
Coal ECBM	Allison	N.A.	183	4	46	*White-2005*
Coal ECBM	Consol	6,700	18	1	18	*NETL-2002*
Coal ECBM	RECOPOL	1,100	17	1	17	NITG-2005

As mentioned previously, all the coal ECBM projects have either been pilot tests or single well "micro-pilot" tests. Based on these tests, CO_2 injectivity ranged from approximately 17 to 46 tons per day per injection well. For purposes of the coal seam ECBM model project, the maximum number of wells for a commercial-scale project is based on the Allison project's average injection rate of 46 tons per day per well. This results in a maximum of 60 CO_2 injection wells (See Section 2.5.5). The minimum number is assumed to be a single injection well pilot (based on Consol and RECOPOL).

A limited review of literature regarding formation CO_2 injectivity was conducted to formulate the model projects for coal seams, EOR, saline formations, and basalt formations. Table 2-17 summarizes the results on porosity and permeability values based on that review.

Table 2-17. Representative Formation Porosities and Permeabilities

Formation/ Formation Type	Porosity, % (Max)	Permeability, mD	References
Coal Seam/ ECBM	<1 - 2	1 – 100	ARI-2003, Bromhal-2004, Reeves-2003, Srivistava-2005, Wolf-2000.
Oil Formation/ EOR	10 - 25	5 – 1000	Knepp-2005, O&GJ-2004, Smith-2005, Stevens-2000, Westrich-2002.
Saline Formation	20 - 40	200 – 3000+	Audigane-2005, Hovorka-2004/2001, Kikuta-2004, Leetaru-2005, Myer-2005, NETL-2003, Saripalli-2005.
Basalt Formation	5 – 40+	1 – 1000+	Kumar-2005, Matter-2005, McGrail-2005a/b, McGrail-2003, O'Connor-2001, Reidel-2002, Saar-1999.

Coal seams contain more water and methane gas and are typically located at shallower depths than oil or saline formations. This significantly reduces the available porosity and limits the CO_2 injectivity, with injectivity being a function of permeability and injection area. Because of the relatively low permeability and porosity of coal seams, along with the tendency for the coal cleats to swell with CO_2 adsorption, more complex well drilling patterns (horizontal wells) and/or fracturing methods may be necessary. Therefore, coal seam/ECBM technologies will tend to have a greater number of injection wells (with tighter spacing) than the other geologic sequestration technologies.

For coal seam ECBM CO_2 injection well spacing, typical well spacings are on the order of 40, 160, or 320 acres (White, 2005). Based on some of the CO_2 injectivity problems experienced with several of the pilot field tests, the model project assumes a 40-acre spacing per CO_2 injection well for the coal seam model project (see Section 2.5.5).

For EOR geologic sequestration applications, a review of the approximately 70 U.S. CO_2 miscible EOR projects was performed. Evaluating the middle 80 percentile of the population of CO_2 EOR fields produced values for field acreage to numbers of CO_2 injection wells ranging from about 30 to 220 acres/injection well, with an average of approximately 74 acres per injection well (O&GJ, 2004). This value was used in the CO_2 EOR geologic sequestration model project to determine the maximum acreage potentially affected by a commercial scale project (see Section 2.5.6). Given the significantly higher permeability of oil formations when compared to coal seams, the EOR CO_2 injection well spacing used in the model project for EOR is almost twice that of the coal seam ECBM model project.

Saline formations show much higher porosities and permeabilities than do oil formations, with basalt formations potentially approaching the injectivity of saline formations, as shown in Table 2-17. For potential well spacing for saline formation applications, a review of the world's largest saline formation CO_2 injection project was performed. Based on the formation modeling studies performed of the stratigraphic and hydrogeologic characteristics of the Dupuy formation, the CO_2 injection wells for the Gorgon project are separated by approximately 2 kilometers by 4 kilometers (6,600 ft by 13,200 ft) grid spacing (Chevron, 2005). These values will be used to estimate CO_2 injection well spacing and total acreage affected for the saline formation geologic sequestration model project (see Section 2.5.7).

For the basalt formation geologic sequestration model project, where adequate data are not available, it is assumed that basalt injectivity characteristics will surpass that of oil formation EOR applications, and approach that of saline formations. Key process and project design parameters were extrapolated from the EOR and/or saline formation model projects.

2.5.3 Post-Combustion Capture

This model project was developed to evaluate the impacts of post-combustion capture technologies. These technologies are expected to be retrofitted to existing industrial facilities where CO_2 formed as a product of combustion of fossil fuel and air is emitted to the atmosphere as a dilute stream (typically 3-15 percent CO_2 in the exhaust stream). The separated CO_2 is transported to a geologic sequestration site for use in EOR or ECBM operations or for storage in underground saline formations. This model project only includes the capture and separation of CO_2 from a flue gas stream. The CO_2 transport and sequestration operations are discussed in separate model projects.

The following sections, which describe the model project, include these elements:

- General design and operating parameters of the project including a process diagram
- Utility requirements and generated emissions
- Site requirements and operations, and
- Construction phase activities.

2.5.3.1 General Design and Operating Parameters

The model project includes an advanced amine-based absorption system to separate CO_2 from the flue gas. As discussed in Section 3.2, this technology is commercially available and is being used to capture CO_2 from flue gas streams. Other post combustion CO_2 capture technologies that are currently being researched include, regenerable solid sorbents that chemically adsorb CO_2, physical adsorption systems that include solid sorbents operating in pressure swing adsorption (PSA) and temperature swing adsorption (TSA) modes to alternately adsorb and desorb CO_2, and gas separation membranes. These technologies are discussed in Appendix B and have not been commercially demonstrated in separating CO_2 from dilute flue gas streams.

In amine based systems, both primary and secondary amines are used in CO_2 capture processes. Monoethanolamine (MEA), considered to be the state-of-the-art technology, gives fast rates of absorption and favorable equilibrium characteristics. Secondary amines, such as diethanolamine (DEA), also exhibit favorable absorption characteristics. To reduce corrosion and amine degradation rates, and improve overall system performance, proprietary chemical inhibitors are added to MEA solutions by the technology vendors (Reddy et al, 2003, Kamijo, 2004). Another vendor uses a blend of MEA and methyldiethanolamine (MDEA), which is a tertiary amine (Chakravarti, et al, 2001). The model project described here reflects the general performance of these commercially available advanced amine based technologies.

A description of the model project parameters is included in Table 2-18. The model includes the capture of CO_2 from an exhaust slipstream of a pulverized coal-fired boiler. The boiler system is assumed to include an ESP for PM control followed by an FGD system for control of SO_2 emissions. Baseloaded boilers ranging between 200 – 500 MW capacity are assumed to be possible candidates for these technologies. Two model project sizes were selected for evaluation. At the low end, a model project that would capture CO_2 from a slip stream of the boiler exhaust was selected to represent a typical pilot-scale project that could be built under Phase II of the program. At the high end of the range, a model project was selected to represent a full-scale commercial installation. Based on these criteria, exhaust streams representative of a 10 MW pilot facility (2-5 percent slip stream of the 200-500 MW baseload boiler size range) and a 300 MW boiler were selected as the source of the captured CO_2. Exhaust flow rates shown in

Table 2-18 were based on a heat rate of 10,000 Btu/kWh typical of old Subpart D coal-fired boilers and an Fd factor of 9,780 dscf/MMBtu based on EPA Method 19 methodology.

The main exhaust stream characteristics are also shown in Table 2-21. Sulfur dioxide emissions are based on 90 percent control on Subpart D boiler (0.12 lb/MMBtu or ~ 5 ppmv at exhaust O_2 concentration of 5 percent). NO_f emissions are uncontrolled at 0.7 lb/MMBtu. Filterable PM emissions are based on uncontrolled AP-42 emission factors for a PC boiler (assuming 10 percent ash content in coal) and 99.9 percent control across the ESP. Condensable PM emissions (typically inorganic including sulphates) were based on AP-42 emission factors for PC boilers with controls. CO_2 emissions were based on exhaust CO_2 concentrations of 14 percent by volume. Assuming a CO_2 capture efficiency of 90 percent, captured CO_2 emissions range between 200 and 6,000 MT per day.

A schematic of the model project with flow rates of key streams is shown in Figure 2-4. Flue gas is passed through a blower to maintain adequate pressure required to overcome the pressure drop across the absorber. It then enters the absorption tower where it is counter-currently contacted with cool lean amine solution. CO_2 is absorbed from the flue gas stream as it passes up the column. The scrubbed flue gas exiting the absorber is washed with water, which is circulated near the top of the absorber column to minimize solvent losses, and routed to the exhaust stack. The CO_2 laden rich amine solution leaving the bottom of the absorber is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

The preheated, rich CO_2 solution enters the top of the stripper tower and flows downward and counter to the stripping agent, which is heated in a reboiler by low pressure process steam. The CO_2 is liberated from the amine solution through the application of heat. Lean solution from the bottom of the stripper is pumped to the rich-lean heat exchanger, cooled, and returned to the absorber. The vapor phase containing CO_2 and water vapor is cooled in a reflux condenser that condenses a large portion of the water vapor. The vapor CO_2 with some residual moisture is then routed to compression, dehydration, and transport.

A portion of the lean amine solution is periodically sent to a reclaimer where it is heated to a higher temperature to distill and reclaim usable solvent that is recycled to the process. Soda ash is added to aid in the precipitation of higher boiling point waste material, which includes heat stable amine salts and other degradation products. The waste is transferred to the plant's wastewater tank for off-site disposal. Additionally, a portion of the lean amine solution returning to the absorbers is filtered using a carbon bed filter package unit.

The model projects described here do not include the compression, dehydration, and transport of CO_2 to the site of injection. A separate CO_2 transport model project (see Section 2.5.4) was developed to evaluate those impacts.

2.5.3.2 Utility Requirements

Utility requirements include steam, electricity, cooling water, and chemicals. Estimates for the model project were based on reported full-scale installation data and vendor process simulation data. A review of the literature data for MEA solvent-based CO_2 capture systems shows estimates of steam usage that range between 2.6 - 5.3 MMBtu steam per pound of CO_2 recovered. For this model project a mid-range value of 4.0 MMBtu steam/MT of CO_2 recovered was used to estimate steam requirements. Between 35 and 1,020 MMBtu/hr of low pressure steam at 50 - 60 psig is estimated for the model project.

Electricity is required to operate the flue gas blower, solvent pumps and coolers. Electricity for separation was assumed as 0.0185 MWh/MT CO_2 recovered based on literature data. This does not include energy for CO_2 compression, which can be significantly greater (about 10 times as much). Electric power requirements for the separation equipment (pumps and blower) are estimated to range between 160 - 4,730 kW and will be drawn from the plant generation capacity.

Cooling water is used primarily to wash the flue gas exiting the absorber. The water is recirculated to the process. However make-up water is added to account for losses in the system. Make-up water requirements are estimated to range between 13 and 395 gpm.

Solvent recirculation rates were assumed as 2.2 gallons solvent per pound of CO_2 removed based on data from two sources. Solvent recirculation rates were estimated to range between 690 and 20,665 gpm for the model project. Approximately 0.05 percent solvent loss is estimated from carryover and formation of heat stable salts. This equates to a make-up solvent flow rate range of 0.3 to 10 gpm required for the model project.

Soda ash (Na_2CO_3) is used to aid in the precipitation of salts in the reclaimer. Soda ash usage is estimated to range between 53 to 1,590 lb/hr.

2.5.3.3 Environmental process discharge streams

Utility requirements include steam, electricity, cooling water, and chemicals. Estimates for the model project were based on reported full-scale installation data and vendor process simulation data. A review of the literature data for MEA solvent-based CO_2 capture systems shows estimates of steam usage that range between 2.6 - 5.3 MMBtu steam per pound of CO_2 recovered. For this model project a mid-range value of 4.0 MMBtu steam/MT of CO_2 recovered was used to estimate steam requirements. Between 35 and 1,020 MMBtu/hr of low pressure steam at 50 - 60 psig is estimated for the model project.

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Soda ash (Na_2CO_3) is used to aid in the precipitation of salts in the reclaimer. Soda ash usage is estimated to range between 53 to 1,590 lb/hr.

2.5.3.4 Site Requirements and Operations

The model project includes one absorber and regeneration train. Major equipment required under both options include, absorber and stripper towers, reboiler, pumps for rich amine, lean amine, and make-up solvent, lean/rich amine heat exchanger, solvent storage tanks, and flue gas blower.

The 10 MW equivalent pilot-scale CO_2 capture plant would include a single absorber and regeneration (stripper) train to handle the flue gas. For the larger commercial scale 300 MW facility, roughly 3 to 4 absorber and regeneration trains will be required. Each absorber train will include 3-4 absorber towers (~ 15 ft. diameter and 80 ft. in height) operating in parallel. A total of 9 - 16 absorber towers will be required. The regeneration train will consist of a total of 3 to 4 stripper towers (~ 15 ft. diameter and 75 ft. in height) operating in parallel. Each train also includes a reboiler, amine pumps, a heat exchanger, storage tanks, and a flue gas blower.

Based on the equipment required, the model project is expected to require about 5 acres of land for the pilot-scale and about 60 acres for the commercial scale facility. Availability of utilities (e.g., water, electricity, and steam) required for daily operation of the facility must be ensured. Since the capture facility will be located adjacent to an existing power plant (or other industrial facility), these utilities are expected to be available. However, the low pressure steam requirement for the commercial scale project would significantly increase the host utility boiler's heat rate.

Adequate access roads to and within the facility will be required to accommodate trucks and heavy machinery. Traffic to and from the capture facility will be infrequent compared to the host facility for the pilot-scale model project. Based on the calculated amine make-up flow rate for the 10 MW slipstream model project, roughly 15,000 gallons of aqueous solvent will be required each month. The solvent will be transported to the site once a month, in nominally 17,000 gallon tank trucks or tank rail cars depending on the available infrastructure. Additionally, soda ash consumption in the reclaimer is about 20 tons each month. Anhydrous soda ash will be supplied by truck once each week in approximately 5-ton shipments.

Liquid and solid wastes that require disposal from the pilot-scale model project include, reclaimer sludge (about 18 tons or 4,300 gallons per month) and spent carbon from the amine filter beds (about 0.5 ton per month). The reclaimer sludge is transferred to a wastewater tank and disposed off once every three months in 17,000 gallon tank trucks. Spent carbon is trucked each month to a nearby landfill for disposal.

For the larger commercial scale model project, traffic flow to the site is expected to be significantly greater. Roughly 15,000 gallons of aqueous solvent will be required each day, which would require daily deliveries in 17,000 gallon tank trucks or deliveries in significantly larger batches in rail cars each week. Soda ash consumption in the reclaimer is about 570 tons per month or about 20 tons per day, requiring four truckloads of 5-ton shipments per day.

Liquid and solid wastes that require disposal from the commercial scale model project include, reclaimer sludge (about 530 tons or 127,000 gallons per month) and spent carbon from the amine filter beds (about 16 tons per month). The reclaimer sludge is transferred to one of several wastewater tanks (about 5 – 10 tanks each of 12,000 gallon capacity) and disposed off once every two to four week period in 17,000 gallon tank trucks. Spent carbon is trucked each week to a nearby landfill for disposal.

To maintain operation of the pilot-scale facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility (coal-fired plant) and the model project. For round-the-clock operation of the pilot-scale model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

For the commercial scale facility, about five operators (one supervisor and four train operators), three mechanics and three instrument technicians will be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility (coal-fired plant) and the model project. For round-the-clock operation of the commercial scale model facility about thirty full-time equivalent skilled personnel would be required to cover three operating shifts each day.

2.5.3.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would involve clearing the ground cover, which is assumed to include lightly wooded trees and brush, followed by minimal grading. A crew of six equipped with appropriate machinery including front-end loaders and chippers will take about 15 days (720 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (steam, electricity), commissioning, etc. would require a larger crew and heavy machinery. A crew of about 150 – 200 construction personnel would require between 6 – 9 months to complete these tasks.

For the commercial scale facility four crews of six equipped with appropriate machinery including front-end loaders and chippers will take about 45 days (8,640 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (steam, electricity), commissioning, etc. would require a larger crew and heavy machinery. A crew of about 500 construction personnel would require about 2 years to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

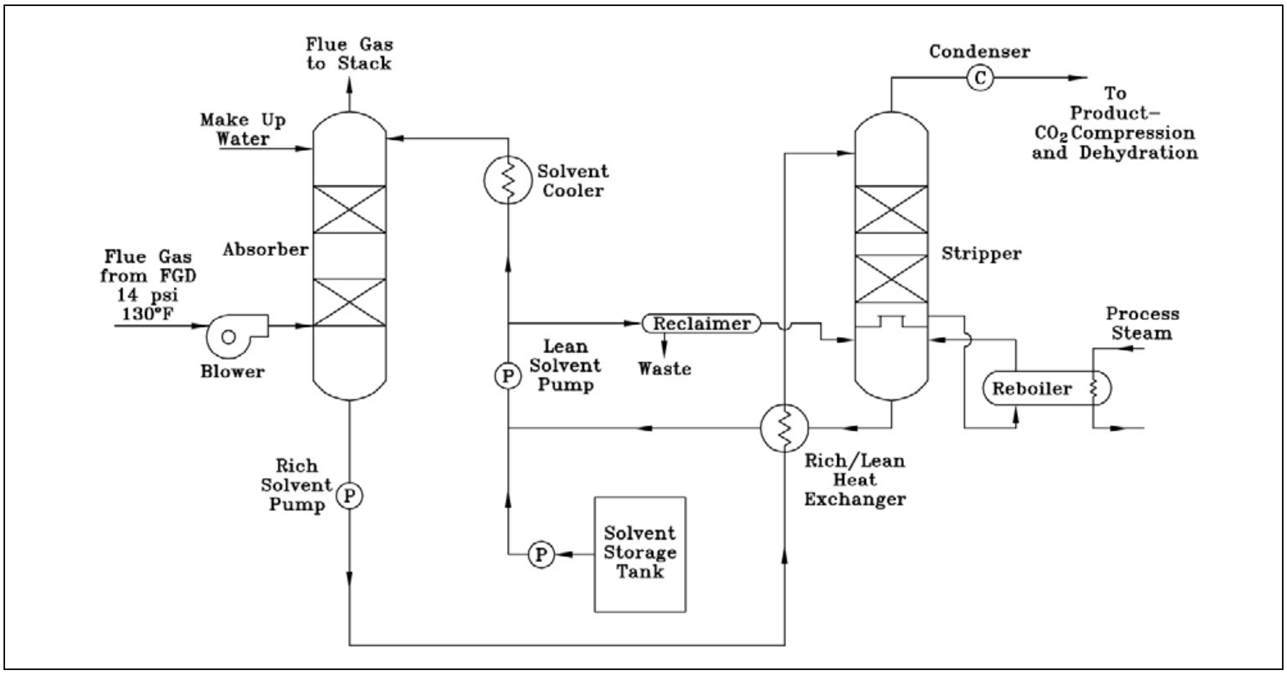


Figure 2-4. Schematic of Post-Combustion Capture Model Project

Table 2-18. Post Combustion Capture Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Plant	Model Plant includes the capture of CO_2 from a slip-stream of a pulverized coal-fired boiler equipped with wet FGD and ESP. Exhaust treatment options include advanced amine absorption. Following separation the CO_2 is sent for dehydration and compression to injection pressures of about 3000 psi.		
Boiler Size (MW)	Based on expected size range	200	500
Slip Stream characteristics			
Slip stream (MW equivalent)	Based on 2-5 % slip stream for a pilot-scale installation at the low end to a typical 300 MW commercial scale installation at the high end.	10	300
Slip Stream (MMBtu/hr equivalent)	Based on a heat rate of 10,000 Btu/kWh	100	3,000
Flow Rate (dscf/hr)	Based on an F_d-factor of 9,780 dscf/MMBtu (USEPA Method 19)	978,000	29,340,000
Slip Stream Gas Composition			
SO_2 (lb/hr)	Based on 90 percent control for Subpart D solid fuel boiler (i.e., 0.12 lb/MMBtu emission rate)	12	360
NO_f (lb/hr)	Based on a NO_f emission rate of 0.7 lb/MMBtu per NSPS Subpart D	70	2,100
PM Filterable (lb/hr)	Based on AP-42 uncontrolled emission factor and 99.9 percent control (i.e., 0.004 lb/MMBtu)	0.4	12
PM condensibles (lb/hr)	Based on AP-42 emission factor	2	60
CO_2 (lb/hr)	Based on exhaust gas concentration of 14 percent by volume	20,872	626,171
Processes:	Flue gas captured from vent stack is treated in amine absorption/regeneration or other adsorption/regeneration trains to separate CO_2, which is sent for dehydration and compression.		
Major Equipment:	Flue gas cooler, absorber tower, amine storage tanks, rich/lean heat exchanger, amine stripper, reboiler, condenser, pumps, blower		
Operating Utilities	Steam, electricity, cooling water, chemicals makeup		
CO_2 captured (lb/hr)	Assuming 90 percent capture efficiency	18,800	563,600
CO_2 captured (MT per day)		205	6,134
Utility and chemical requirements			
Steam (MMBtu/hr)	Based on the following range Praxair (Chakravarti et. al., 2001) =4 to 5 MMBtu/MT CO_2 recovered. SFA (Simbeck, 2001) = 2.6, EPRI (Case 7A) = 4.8, Nexant (Chinn et. al., 2004) = 5.3. RITE (Morimoto, et. al., 2002) =3.2 Used mid-range value of 4.0 for the model project.	34	1,022
Electricity (kW)	Based on energy for separation of 0.0185 kWh/kg CO_2 recovered (Morimoto, et.al., 2002)	160	4,730
Water (gpm)	Based on 180 gpm required for 2,800 MT per day recovered CO_2 plant.	13	394
Water use (gals/day)		18,720	567,360
Solvent Recirculation rate (gpm)	Based on recirculation. rate of 2.2 gal MEA solution/lb CO_2 removed – (EPRI study, case 7A); Chinn et. al., 2004 = 2.18.	689	20,664
Solvent make-up (gpm)	Based on 0.05 per cent loss (Chinn et. al., 2004)	0.34	10.3
Solvent Delivery (gals/day)		500	15,000
Soda Ash (lb/hr)	Based on 168 kg/hr for a 4800 gpm solvent recirculation rate (Chinn et. al., 2004)	53	1,591
Wastes generated			
Reclaimer sludge (lb/hr)	Based on 5000 MT/yr sludge for a 5200 MT per day recovered CO_2 plant (Simmonds, et. al., 2003)	50	1,485
Spent Carbon (lb/hr)	Based on 114 kg/day for 4800 gpm solvent recirculation rate (Chinn et. al., 2004)	1.50	45
Physical Attributes			
Land Requirement (Acres)		5	60

2.5.4 CO_2 Transport Model Projects

These model projects were developed to evaluate the impacts of transporting CO_2 to a sequestration site. Two options are evaluated. The first option involves the compression and transport of a CO_2 stream to a commercial-scale sequestration site that is located within 20 miles of the CO_2 capture site. In this option CO_2 is obtained following separation from a flue gas stream or is obtained as a pure CO_2 stream from natural gas processing or ethanol plants. Alternatively, the CO_2 gas stream obtained from IGCC plants or sour gas processing facilities contain significant quantities of H_2S and require compression and transport prior to sequestration in saline formations or EOR projects.

In the second option, CO_2 is transported in tank trucks to sequestration sites that are not located close to a CO_2 capture site or a CO_2 pipeline. These models describe facilities will be required to supply CO_2 at required injection pressures in pilot-scale projects that demonstrate the feasibility of CO_2 sequestration operations.

The following sections, which describe the model projects, include these elements:

- General design and operating parameters of the project including a process diagram
- Utility requirements and generated emissions
- Site requirements and operations, and
- Construction phase activities.

2.5.4.1 Case A: Compression and Transport of Captured CO_2 by Pipeline

2.5.4.1.1 <u>General Design and Operating Parameters</u>

CO_2 that is obtained from sweet gas plants or separated from flue gas streams is typically at atmospheric pressure and contains 96-98 percent CO_2, 1-3 percent moisture, and traces of other compounds. For example, CO_2 obtained from sweet gas plants could contain methane (CH_4) and traces of hydrogen sulfide (H_2S). CO_2 gas streams obtained from IGCC plants and/or sour gas processing facilities contain up to 45 percent H_2S.

Table 1-1 shows the CO_2 gas parameters. The gas stream parameters and analysis shown in the table reflect an almost pure CO_2 gas stream containing negligible quantities of H_2S. Differences in results caused by the high H_2S concentration case are discussed as appropriate. Two model project sizes were selected for analysis. At the low end is a transport model project capable of handling about 200 MT CO_2 per day, which is representative of the volume captured from a pilot-scale CO_2 capture project. At the high end, the transport model is capable of handling about 2,740 MT CO_2 per day, which is representative of the volume required for typical commercial scale geologic sequestration operations. The gas is assumed to contain 96 percent CO_2, 3 percent H_2O, and 1 percent of other constituents. Prior to transport and injection, the CO_2 is compressed and dehydrated to meet pipeline specifications. Figure 2-5 shows a schematic of the model project. CO_2 at atmospheric pressure is compressed to a discharge pressure of about 1400 psi using a 4-stage compressor unit with interstage coolers and water knockouts. At this pressure, CO_2 behaves as a liquid and further compression to injection pressures of about 3000 psig is achieved using a single-stage pump unit. Between the third and fourth stages of compression, CO_2 gas is dehydrated in a triethylene glycol (TEG) dehydrator unit.

For the transport of the high H_2S concentration acid gas streams, the CO_2 flow rate depends on the concentration of CO_2 in the gas stream. The low-end transport model gas stream is assumed to contain about 2 percent H_2S, which corresponds to a slip stream from an IGCC or sour gas processing plant. The CO_2 flow rate is approximately 200 MT per day. For the commercial scale transport model the gas stream is assumed to contain about 25 percent H_2S (by weight), which corresponds to a typical commercial scale sour gas processing plant. The CO_2 flow rate is about 2055 MT per day.

Compression of the acid gas stream prior to transport and injection can be achieved using a 4-stage compressor unit similar to the compression of pure CO_2 stream shown in Figure 2-5. Depending on the H_2S content and gas temperature, the solubility of water in the gas decreases with increasing pressure (Bachu and Gunter, 2004). Therefore compression above 450 and 750 psig tends to naturally dewater the gas, thereby avoiding the need for dehydration using TEG.

2.5.4.1.2 Operating Utilities and Materials

For the model project, energy is required to operate the compressors and pump. Based on availability of natural gas fuel or electricity, the compressors and pump can be driven either by gas-fired internal combustion (IC) engines or by electric motors. A small quantity of gas fuel is also required to operate the reboiler in the dehydrator unit. Based on compressor operating parameters and gas conditions, energy usage was calculated as 6,700 kWh/MMscf compressed gas assuming that electric-drive motors are used as prime movers for the compressors and pump. If natural gas is used as fuel for gas-fired engine prime movers, energy usage is estimated as 72 Btu/scf gas compressed based on engine brake specific fuel consumption (bsfc) of 8,000 Btu/hp-hr. These estimates of energy usage are consistent with values in the published literature (Morimoto, et. al., 2002). Dehydrator fuel usage is small in comparison, estimated to be about 0.5 Btu/scf gas processed.

Energy requirements are similar for the acid gas compression assuming similar suction and discharge pressures. Actual discharge pressures depend on formation conditions. Since a dehydration step may not be required, it will result in dehydrator fuel usage savings.

To maintain operation of IC engines, lubrication oil and cooling water are required. Based on installed capacity of 2,000 hp for the pilot-scale and 25,000 hp for the commercial scale installation (requirement is 1,400 – 20,000 hp), lubricating oil consumption is estimated at 12 - 150 gallons per day.

2.5.4.1.3 Environmental Process Discharge Streams

The use of natural gas as fuel for the IC engines results in emissions of CO_2, CH_4, and criteria pollutants, including NO_f, CO, and VOCs. CO_2 emissions vary between 1,260 – 17,200 lb/hr and methane emissions range between 17 - 227 lb/hr. Assuming a global warming potential for CO_2 of 1 and for CH_4 of 21, the CO_2 equivalent (CO_2 e) emissions range between 1,600 – 21,950 lb/hr, which is about 9 percent of the CO_2 compressed. NO_f emissions range between 36 - 495 lb/hr, CO emissions range between 4 - 60 lb/hr, and VOC emissions range between 1.4 – 19 lb/hr.

Condensate from the compressed gas stream is generated at rates that range between 200 – 2,900 lb/hr. The condensate is transferred to a wastewater tank for off-site disposal. Based on engine maintenance schedules, used engine oil wastes are generated. Between 150 – 1,875 gallons of used oil is generated every four months (assuming an oil change every 3,000 hrs of operation). The oil is transferred to a waste oil tank for periodic off-site disposal.

Additional liquid wastes include oils and grease used for maintenance activities. Similar waste streams are typically generated at utility and industrial facilities and the incremental quantities of oil and grease wastes generated by the model project will not require significant additional waste handling measures.

2.5.4.1.4 Site Requirements and Operations

The pilot-scale model project includes about 4 engine-compressor units and one pump unit with a total installed capacity of about 2,000 hp. If electric-drive motors are used instead of IC engine-driven compressors, five motors with a total installed capacity of about 1,500 kW are required. The compressor units will be housed in a compressor building with an approximate plan dimension of 50 feet by 100 feet. A TEG dehydration system capable of processing 4 MMscfd of CO_2 gas is required. The system includes contactor and stripper towers, reboiler, TEG pumps, heat exchanger, and solvent storage tanks.

Additional space to accommodate piping manifolds, knockouts, and wastewater and used oil tanks is required.

The commercial scale model project includes about 8-10 engine compressor units and 2 pump units with the total installed capacity of about 25,000 hp. If electric-drive motors are used instead of IC engine-driven compressors, about 10 - 12 motors with a total installed capacity of about 19,000 kW are required. The compressor units will be housed in about 5 compressor buildings each with an approximate plan dimension of 50'x100'. A TEG dehydration system capable of processing about 55 MMscfd of CO_2 gas is required. The dehydration system equipment is similar to that described for the pilot scale model project but will have much larger dimensions to accommodate the increased gas flow rates.

Based on the equipment required, the pilot-scale model project is expected to require about 2 acres of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured. Since the compression and transport facility will be located adjacent to an existing industrial facility, these utilities are expected to be available.

To accommodate the larger plant size, the commercial scale model project is expected to require about 20 acres of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured. If electric motors are used to drive the compressors, electric power of ~ 15 MW will be required. If natural gas-fired engines are used to to drive the compressors, total engine heat input is estimated as156 MMBtu/hr (~150,000 scf/hr natural gas). The CO_2 compressor station will require access to the local grid and natural gas pipeline delivery.

Adequate access roads, to and within the facility, will be required to accommodate trucks and heavy machinery. Traffic to and from the facility will be infrequent. Water condensed from the gas will be transferred to a wastewater tank. Wastewater will be disposed off once a month for the pilot facility and once every two days for the commercial scale facility in 17,000-gallon tank trucks.

Used engine lubricating oil will be transferred to a used oil tank and disposed off once every six months for the pilot facility and once a month for the commercial scale facility.

To maintain operation of the pilot-scale facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility and the model project. For round-the-clock operation of the model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

The commercial scale facility will require about three operators, two mechanics, and two instrument technicians. For round-the-clock operation about 20 full time equivalent skilled personnel would be required to cover three operating shifts each day

2.5.4.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would involve clearing the ground cover, which is assumed to include lightly wooded trees and brush, followed by minimal grading. A crew of six equipped with appropriate machinery including front-end loaders and chippers will take about 7 days (336 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (natural gas, electricity), commissioning, etc. would require a larger crew and heavy machinery.

For the small-scale pilot transport model project, about 0.25 miles of 6-inch carbon steel pipeline would be buried underground to transport the pure CO_2 stream to the sequestration site (e.g., a slip-stream from a major CO_2 source to a geologic sequestration location, either co-located on the same site or on an adjacent industrial property). Approximately 50 feet of a 75 foot existing right of way would be disturbed for pipeline construction activities (both for the pilot and commercial scale facility). For transport of acid gas carbon steel can be used although stainless steel is preferred because of the corrosive nature of the

H_2S in the stream. Usually 304/316L stainless steel is employed for best corrosion resistance (Carroll, 1999). A crew of about 25-50 skilled construction personnel would require about 8 months to complete these tasks.

For the commercial scale facility, three crews of six each equipped with appropriate machinery including front-end loaders and chippers will take about 25 days (3,600 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (natural gas, electricity), commissioning, etc. would require a larger crew and heavy machinery. About 20 miles of about 8-inch pipeline would be buried underground to transport the CO_2 to the sequestration site. For transport of acid gas, use of stainless steel pipeline is preferred. A crew of about 100 skilled construction personnel would require about 12 to 18 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.4.2 Case B: Compression and Transport of Liquified CO_2 by Refrigerated Tank Trucks

2.5.4.2.1 General Design and Operating Parameters

For sequestration projects that are not located near CO_2 capture sites or near existing CO_2 pipelines, liquid CO_2 can be transported to the sequestration site in tank trucks. A schematic of the model project is shown in Figure 2-6. Liquid CO_2 is delivered in commercial refrigerated tank trucks that travel about 100 miles (roundtrip) to the sequestration site. Each truckload is capable of supplying about 20 MT of CO_2. At the sequestration site CO_2 is transferred to large storage tanks that are maintained at about 300 psig and 0 deg F.

The CO_2 is further compressed to injection pressures by skid-mounted pumps located at the sequestration site. In certain cases, if CO_2 gas injection is required, vaporizer units will be required. Vaporizers are not included in this model plant.

2.5.4.2.2 Operating Utilities and Materials

Liquid CO_2 from the supply tank trucks is pumped to the on-site storage tanks by individual truck-mounted pumps. Electricity is required to operate the on-site pumps that compress CO_2 from tank pressures of 300 psig to injection pressures of about 3,000 psig. Based on the injection rates of about 100 – 200 MT/day, electric power requirements are estimated as 75 –150 kW (Table 2-20). If natural gas-fired IC engines are used to drive the pumps, fuel requirements are estimated as 10 MMBtu/MMscf gas compressed, based on an engine bsfc of 8,000 Btu/hp-hr.

To maintain operation of IC engines, lubrication oil and cooling water are required. Based on installed capacity of 150-300 horsepower (requirement is 100-200 hp), lubricating oil consumption is estimated at 0.6 - 1.2 gallons per day.

2.5.4.2.3 Environmental Process Discharge Streams

The use of natural gas as fuel for the IC engines results in emissions of CO_2, CH_4, and criteria pollutants, including NO_f, CO, and VOCs. CO_2 emissions vary between 87 - 175 lb/hr and methane emissions range between 1.2 – 2.3 lb/hr. Assuming a global warming potential for CO_2 of 1 and for methane of 21, the CO_2 equivalent emissions range between 111 and 222 lb/hr, which is about 1 percent of the CO_2 compressed and ultimately sequestered. NO_f emissions range between 3 - 5 lb/hr, CO emissions range between 0.3 – 0.6 lb/hr, and VOC emissions range between 0.1 – 0.2 lb/hr.

The project also results in mobile source emissions from the commercial tank trucks supplying liquid CO_2 to the sequestration site. Assuming the supply facility is located about 50 miles from the sequestration site (i.e., 100 - mile round-trip), CO_2 emissions from gasoline fuel combustion in the supply truck were estimated to range between 70 – 140 lb/hr. Methane and nitrous oxide (N_2O) emissions were lower. The CO_2e emissions (assuming a GWP of 310 for N_2O) are estimated to range between 80 – 160 lb/hr or less than 1 percent of the CO_2 compressed and ultimately sequestered. NO_f emissions range between 0.1 – 0.3 lb/hr and CO emissions range between 0.7 – 1.3 lb/hr.

Based on engine maintenance schedules, used engine oil wastes are generated. About 25 - 40 gallons of used oil is generated every four months (assuming an oil change every 3,000 hrs of operation). The oil is transferred to a waste oil tank for periodic off-site disposal.

Additional liquid wastes include oils and grease used for maintenance activities. Similar waste streams are typically generated at utility and industrial facilities and the incremental quantities of oil and grease wastes generated by the model project will not require significant additional waste handling measures.

2.5.4.2.4 Site Requirements and Operations

The model project includes about 3 to 4 IC engine-driven pump units with a total installed capacity ranging between 150 - 300 hp. Electric-drive motors (115 – 225 kW) can be used instead of IC engines to provide power for operating the pumps. The pumps will be housed in a building with an approximate plan dimension of 50'by 50'. Between 2 to 4 large insulated tanks are required to store the liquid CO_2 supplied by the tank trucks. Additional space to accommodate CO_2 supply tank trucks, piping and manifolds, and used oil tanks is required.

Based on the equipment required, the model project is expected to require about 1 acre of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured.

Adequate access roads, to and within the facility, will be required to accommodate trucks and heavy machinery. Traffic to and from the facility will be frequent. Based on a truckload of 20 MT of CO_2, between 5-10 truckloads are required each day. Used engine lubricating oil will be transferred to a used oil tank and disposed off once every six months.

To maintain operation of the facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the sequestration facility and the model project. For round-the-clock operation of the model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

2.5.4.2.5 Construction Phase Activities

No additional construction activities beyond that of the existing geologic sequestration facility in question would be required for truck transport of CO_2.

Table 2-19. Model A: Captured CO_2 Compression and Transport Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Project	Model plant includes the compression and dehydration of CO_2 that is captured at atmospheric pressure. CO_2 is compressed to an injection pressure of 3,000 psi and used in geologic sequestration activities. (i.e, enhanced oil recovery, enhanced coalbed methane, or storage).		
Slip Stream characteristics			
Flow Rate (lb/hr)	Low end of range based on 200 MT per day (~10 MW slip stream) capture CO_2 pilot-scale facility. High end of range based on 2,700 MT per day (~ 1,000,000 MT per year) commercial scale geological sequestration operation.	18,375	251,700
Flow Rate (MT/day)		200	2,740
Flow Rate (MT/Year)		73,000	1,000,100
Flow Rate (scf/day)		3,802,623	52,090,722
CO_2 (lb/hr)	Based on 96 percent CO_2 by volume	17,640	241,644
Moisture (lb/hr)	Based on 3 percent water by volume	226	3,089
Processes:	CO_2 that is captured and separated from flue gas is compressed and dehydrated to injection pressures of 3,000 psi for use in geologic sequestration activities. The model assumes that the CO_2 source is within 10 miles from the point of injection		
Major Equipment:	CO_2 gas compressors (IC engine or electric motor driven), intercoolers, and associated auxiliary equipment, dehydrator, water knockouts, up to 20 miles of pipeline,		
Operating Utilities	Natural gas fuel and/or electricity		
Operating Utilities and Materials			
Natural Gas Fuel -IC Engines (MMBtu/hr)	Based on 72 MMBtu/MMscf CO_2	11.4	156
Natural Gas Fuel - Dehydrator (MMBtu/hr)	Based on 0.5 MMBtu/MMscf of CO_2 processed	0.08	1.1
Electric power- Motors (kW)	Based on 6,700 kWh/MMscf CO_2 compressed	1,062	14,542
Lubricating oil (gal/day)	Based on 0.5 gal/hr for a 2,000 hp unit	12	156
Emissions from IC Engine combustion			
CO_2 (lb/hr)	Emission factor (EF) =110 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1,255	17,190
CH4 (lb/hr)	Emission factor (EF) =1.45 lb/MMBtu (USEPA AP-42 Table 3.2-1)	17	227
NO_f (lb/hr)	Emission factor (EF) = 3.17 lb/MMBtu (USEPA AP-42 Table 3.2-1)	36	495
CO (lb/hr)	Emission factor (EF) =0.386 lb/MMBtu (USEPA AP-42 Table 3.2-1)	4.4	60
VOC (lb/hr)	Emission factor (EF) =0.12 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1.4	19
Wastes generated			
Water discharge (lb/hr)	Based on pipeline spec. of 4 lbs H_2O/MMscf	210	2,880
Water discharge (gal/day)	Converted lbs to gallons	604	8,283
Used lubricating Oil (gal/month)	Based on 100-150 gallons per oil change every 3,000 operating hrs.	38	470
Physical Attributes			
Land Requirement (Acres)	Land for compressor facilities	2	20
Pipeline Disturbance (Acres)	Assumes 50' of a 75' corridor would be disturbed. Minimum case is 0.25 miles and Maximum case is 20 miles	1.5	121
Total Land Disturbance (Acres)	Facilities and Pipeline	3.5	141

Table 2-20. Model B: Liquid CO_2 Transport Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Project	Model plant includes the storage of liquid CO_2 that is transported to the sequestration site by commercial refrigerated tank trucks. The CO_2 is pumped to injection pressures of 3,000 psig at the site prior to injection in geologic sequestration activities. (i.e, enhanced oil recovery, enhanced coalbed methane, or storage).		
Supply Rate (MT/day)	Based on similar flow rate as captured CO_2 transport volumes	100	200
Truckloads per day	Based on 20 MT per truckload	5	10
Processes:	CO_2 is supplied by refrigerated tank trucks to the sequestration site where it is transferred to one or more large insulated tanks maintained at 300 psig. At the site, a pumping station that includes 3-4 pumps is used to pump the liquid CO_2 at injection pressures of about 3,000 psig. The model assumes that the CO_2 supply tank trucks travel about 100 miles round trip.		
Major Equipment:	Insulated CO_2 storage tanks, CO_2 pumps (IC engine or electric motor driven).		
Operating Utilities	Natural gas fuel and/or electricity		
Operating Utilities and Materials			
Fuel -IC Engines (MMBtu/hr)	Based on 10 MMBtu/MMscf CO_2	0.8	1.6
Electric power- Motors (kW)	Based on 930 kWh/MMscf CO_2 compressed	74	147
Lubricating oil (gal/day)	Based on 0.5 gal/hr for a 2,000 hp unit	0.60	1.20
Emissions from Stationary IC Engine combustion			
CO_2 (lb/hr)	Emission factor (EF) = 110 lb/MMBtu (USEPA AP-42 Table 3.2-1)	87	174
CH_4 (lb/hr)	Emission factor (EF) = 1.45 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1.2	2.3
NO_f (lb/hr)	Emission factor (EF) = 3.17 lb/MMBtu (USEPA AP-42 Table 3.2-1)	2.5	5
CO (lb/hr)	Emission factor (EF) = 0.386 lb/MMBtu (USEPA AP-42 Table 3.2-1)	0.3	0.6
VOC (lb/hr)	Emission factor (EF) = 0.12 lb/MMBtu (USEPA AP-42 Table 3.2-1)	0.1	0.2
Mobile Source Emissions			
CO_2 (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = 0.0709 MT/MMBtu (API Compendium, Table 4-1)	71	141
CH_4 (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = $6.4x10^{-4}$ MT/1000 gal (API Compendium, Table 4-9)	0.01	0.01
N_2O (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = $3.8x10^{-3}$ MT/1000 gal (API Compendium, Table 4-9)	0.03	0.06
NO_f (lb/hr)	Based on 100 mile round trip and EF = 3.02 g/mile (USEPA AP-42, Appendix H, Table 4.1A.1)	0.1	0.3
CO (lb/hr)	Based on 100 mile round trip and EF = 14.23 g/mile (USEPA AP-42, Appendix H, Table 4.1A.1)	0.7	1.3
Wastes generated			
Used lubricating Oil (gal/month)	Based on 25 - 40 gallons per oil change every 3,000 operating hrs.	6.25	10

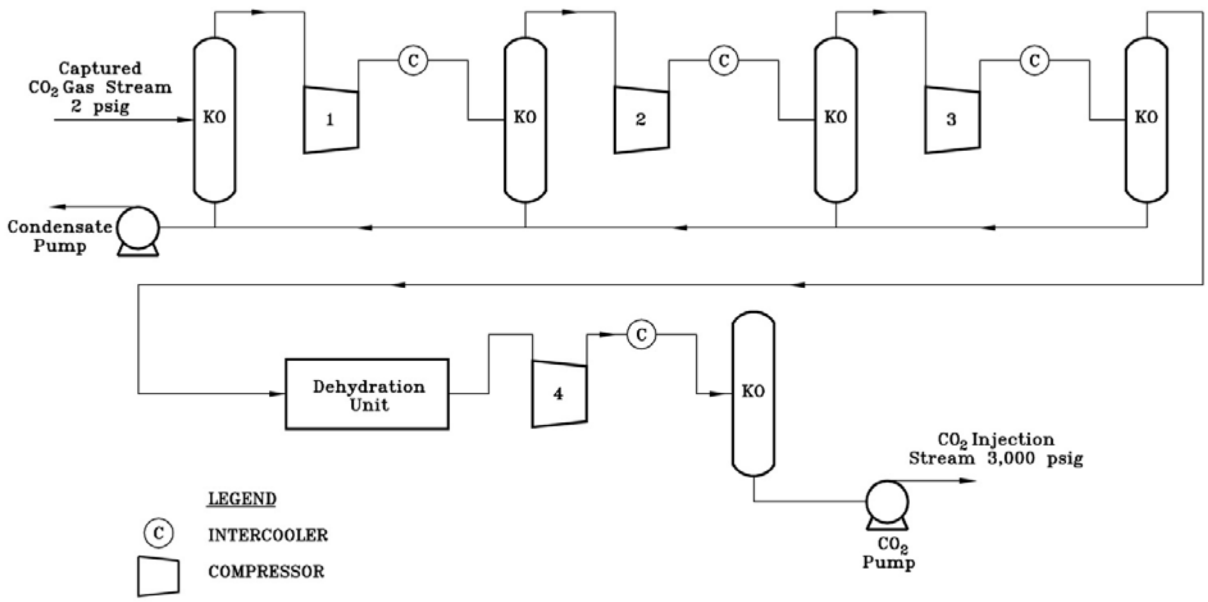


Figure 2-5. Schematic of Captured CO_2 Compression and Transport Model Project (Model A)

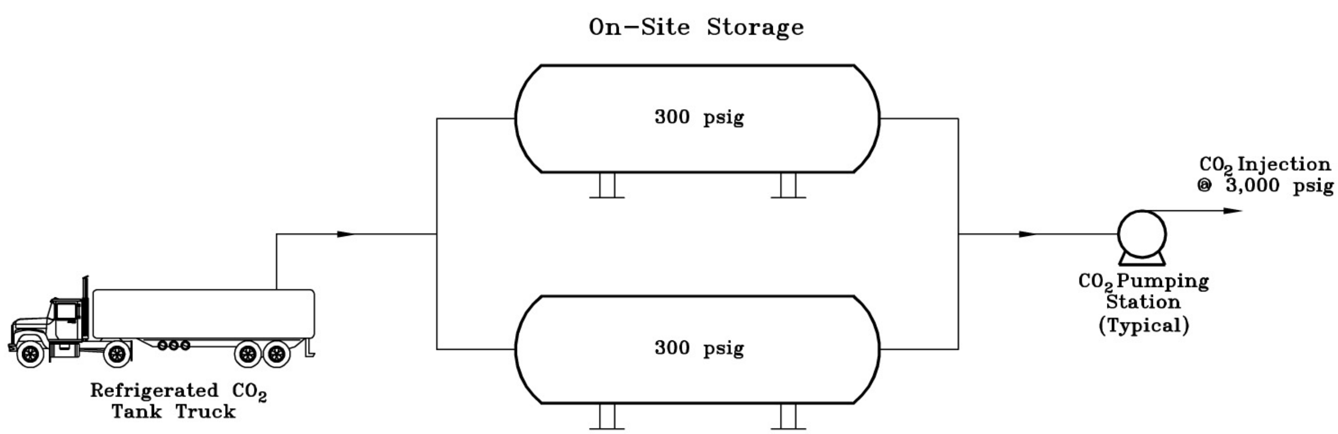


Figure 2-6. Schematic of Refrigerated CO_2 Transport and Compression Model Project (Model B)

2.5.5 Coal Seam Sequestration and Enhanced Coalbed Methane Recovery Model Project

This model project was developed to evaluate the impacts of CO_2 sequestration in deep, unmineable coal seams. The coal seam sequestration model project would consist of transporting CO_2 on site from a nearby source, heating and regulating the pressure of the CO_2, and injecting CO_2 into the coal seams. Although methane recovery may not be appropriate for all locations at which this model project may be implemented, recovering marketable coalbed methane (CBM) would be addressed in this model project description.

Coal seam sequestration of CO_2 has occurred in two known pilot projects in the U.S. Therefore, the technology to operate coal seam CO_2 sequestration projects has been developed. These projects have operated with appropriate permits and approvals, as applicable by their respective states, including completing the NEPA review process and acquiring environmental permits, such as an air quality permit. Additional descriptions of current sequestration technologies are discussed in Section 2.2.

The following sections, which describe the model project, include these elements:

- General design and operating parameters including Monitoring, Mitigation, and Verification (MM&V);
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.5.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing pilot projects of CO_2 and nitrogen (N_2) injection into coal seams, as well as geological recommendations from team personnel. The three existing pilot projects that were reviewed are the Allison Unit CO_2 Project and the Tiffany Unit N_2 Project, both conducted in the San Juan Basin in New Mexico and Colorado, and the CONSOL Energy CO_2 project in West Virginia. All three projects also recovered CBM.

A description of the model project parameters is included in Table 2-21. CO_2 injection at the Allison Unit averaged 232 tons per day from four wells. CONSOL Energy will conduct a small scale research and design project in West Virginia which expects an averaged injection rate of 36 tons of CO_2 per day. To ensure the model project encompasses injection rates similar to the above examples, the following range of CO_2 average daily injection rates would be used: 35 tons/day (11,590 MT per year) as a minimum from one well and 2,750 tons/day (910,600 MT per year) as a maximum from twelve wells.

The number of injection wells would range from 1 to 12. This range is based on the Allison Unit project for the minimum value, and an average daily injection rate of 230 tons/day from a single well (Allison Unit) for the maximum value. The majority of other project data (number of CBM production wells, site acreage, miles of access roads, etc.) is based off of the number of injection wells. The number of CBM recovery wells range from 2 to 20, based on either a 3-spot configuration like the CONSOL project or a 5-spot configuration (see Figure 2-7). Between 1 and 8 monitoring wells would be installed for various MM&V requirements. All wells would be new construction.

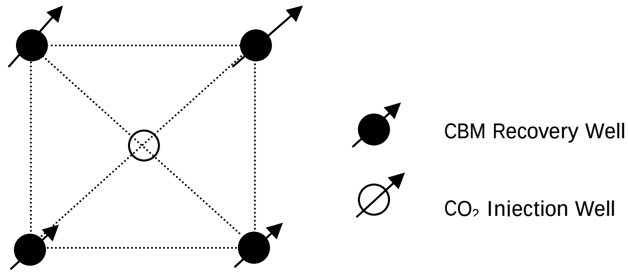


Figure 2-7. Typical 5-Spot Well Configuration

Depending on the depth of the coal seam, wells may extend from 1,000 to 2,500 feet in depth, with the coalbed ranging from 10 feet to 200 feet thick. The United Mine Workers of America (UMWA) website states that almost all underground coal mines in the U.S. are less than 1,000 feet deep; therefore, this was used as the minimum depth value. 2,500 feet is the maximum depth as it is the deepest active mine in the U.S. (Alabama). The question of whether a coal seam is mineable or not depends on location, depth specifics, economic feasibility, and ownership of the coal, as industry will determine what is mineable and what are future coal reserves. The ranges for the coal seam thickness are based on the Allison Unit for a minimum and geologic input for the maximum. Single coal seams of 40 – 200 feet are specific to the western states. Coal seams in the east can vary from 2 – 7 feet thick, so multiple seams are ideal.

A range of 0.02 mile to 4.1 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum value assumes the distribution lines would begin at one central location and distribute out to two main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. As discussed later, injection and recovery wells are a maximum of 1,800 feet apart. This piping would be buried to insure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for both CO_2 injection and CBM production anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (see Figure 2-8 for a flow diagram). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A gas-fired heating unit would be anticipated as the CO_2 would most likely require heating to raise the temperature to equal that of the coalbed (Reeves et al., 2003). Following the heating unit is a pressure regulator, which would ensure constant pressure of the CO_2. A flow meter would regulate the injection rate, and a Supervisory Control and Data Acquisition (SCADA) system would monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup. The footprint for the CO_2 injection surface configuration is anticipated to be about 150 square feet.

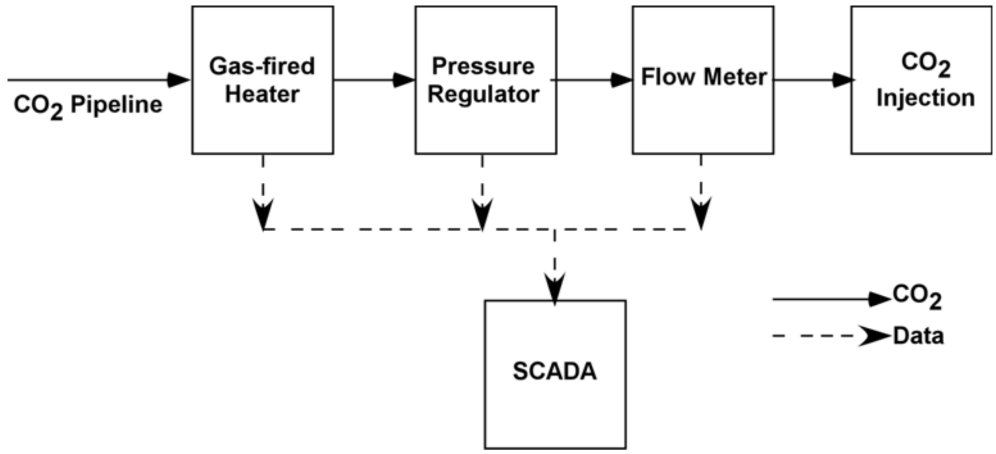


Figure 2-8. CO_2 Injection Well Surface Configuration

The surface configuration for a CBM production well would consist of a gas/water separator, surface pressure regulation, gas flow meter, a SCADA system, and produced water storage, as shown in the flow diagram in Figure 2-9 (Reeves et al., 2004). Storage tanks with a total estimated storage capacity ranging from 500 gallons to 10,000 gallons would store water recovered during CBM recovery until it can be transported off-site for treatment and discharge. Assuming wastewater generation of these storage capacities per week derives a minimum of 2.98 gallons per hour and a maximum of 59.5 gallons per hour. Two additional options to wastewater discharge include reinjection at greater depths, as long as the water below the coal seam is of lesser quality, or use of a submerged evaporator to evaporate the water leaving salt for disposal. The estimated footprint for the CBM recovery surface configuration is approximately 1,600 square feet. On-site compression is not currently anticipated for the recovered CBM. A pipeline would transport the CBM off-site for CO_2 removal and compression for transmission.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the coal seam, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, measurement of in-situ temperature and pressure, and electromagnetic imaging.

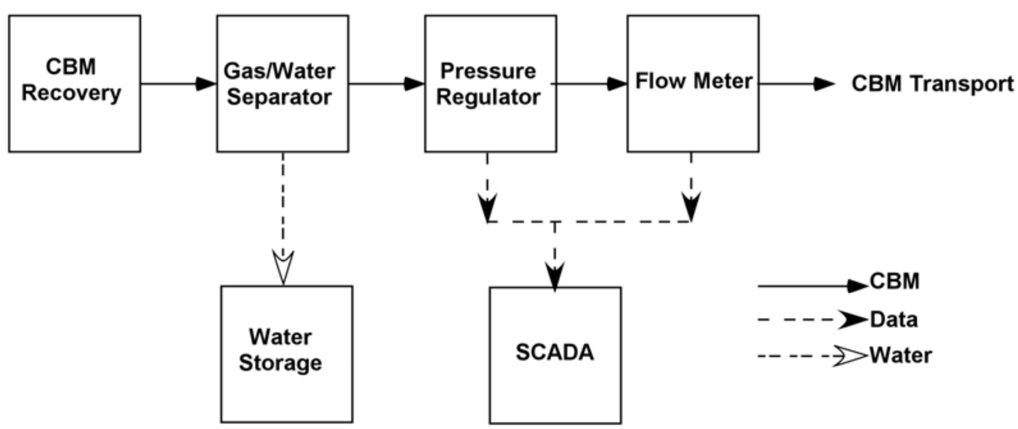


Figure 2-9. CBM Production Well Surface Configuration

2.5.5.2 Utility Requirements

Utility requirements for the model project include fuel usage. Fuel would be trucked on site for the injection well heating unit. The estimated annual distillate fuel usage is 2,884 gallons for the minimum scenario and 226,560 gallons for the maximum scenario. No additional on-site fuel storage is anticipated.

The annual electricity usage rates for CO_2 Enhanced Oil Recovery (EOR) operations as discussed in the EOR Model Project description is estimated at 1.86 hp per million standard cubic feet (MMscf). This usage rate value includes CO_2 compression, pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. The following conversion excludes CO_2 compression, which is accounted for in the CO_2 Compression and Transport Model Project description. In order to use this value for estimating electricity requirements, minimum and maximum injection rates in million standard cubic feet per day (MMscfd) are converted to minimum and maximum annual electricity requirements of 519 kilowatts (kW) and 11,826 kW, respectively.

2.5.5.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. The use of distillate fuel for the heating unit is assumed to conservatively estimate the air emissions, which are detailed in Table 2-21.

Wastewater from CBM recovery wells may contain elevated levels of dissolved solids as well as organic and inorganic compounds. The wastewater could either be transferred to a storage tank for periodic off-site treatment and disposal or discharged under a National Pollutant Discharge Elimination System (NPDES) permit with limited treatment.

Well drilling cuttings would require collection and management. An estimated 873 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 2,500 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.5.4 Site Requirements and Operations

Detailed geologic and hydrogeologic information must be included in any model to accurately portray the potential environmental impacts of injecting CO_2 into the system. Because this is a hypothetical project, it is assumed that the site would have favorable hydrogeologic characteristics for this type of project:

- Faults and fractures present in the seam would have minor displacement.
- There would be limited CO_2 migration pathways between the coal seam and any potable water supply aquifer.
- The ratio of existing methane to water in the coal seam would be at least equal.
- The formation water in the coal seam would have sufficiently low dissolved constituent concentrations, thus requiring only limited treatment after its co-production with the CBM prior to its subsequent discharge.
- No methane or other gas would be liberated from outcrop areas of the coal seam as a result of groundwater level drawdown.

It is assumed that the model project would be co-located with a CO_2 source: therefore, a nearby pipeline would provide the necessary CO_2 for injection. Refer to Compression and Transport of Captured CO_2 Model Project description for additional information. The site should range from 90 to 1,500 acres.

A minimum and maximum distance between production and injection wells would be 1,000 feet and 1,800 feet, respectively (Reeves et al., 2002; NETL, 2002).

CBM production is anticipated to operate for one to three years prior to start up of CO_2 injection, and would continue to operate during injection. Note that in marginally gassy coal seams, there may be no initial CBM production; however CO_2 injection could be the catalyst to bring CBM production up to economic feasibility. CO_2 injection and CBM production would occur continuously with three shifts. It is anticipated that a smaller site would be automated, and one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and if needed, operation.

2.5.5.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For 1,500 acres of land, a maximum of 13.6 miles of new dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 244 acres would be required for roads and equipment locations. This value is based on clearing 13.6 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of twelve equipped with appropriate machinery including front-end loaders and chippers would take about 15 days (1,440 man-hours) to prepare the site. For the 90 acre pilot scale site it is estimated a crew of three could prepare the site in 5 days.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of about 20 – 80 construction personnel would require between 3 – 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-21. Sequestration of CO_2 - Coal Seam and CBM Model Project Data Sheet

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Coal Seam Depth	1,000 feet	2,500 feet	UMWA
Coal Seam Thickness	10 feet	200 feet	Based on Allison Unit and URS geologic input
Coal Permeability	Medium	High	Low permeability would limit sequestration amount
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	90	1,500	Based on the number of wells and the distance between
Clearing (acres)	19	244	Minimum and maximum based on 1 mile and 66 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
Distance btw Wells	1,000 feet	1,800 feet	Based on CONSOL and Allison Projects
Injection Wells	1	12	Minimum based on Allison Project. All wells are new.
CBM Production Wells	2	20	Based on 3-spot and 5-spot patterns for 4 to 12 wells. All wells are new.
Observation/Monitoring Wells	1	8	Minimum based on CONSOL Project. All wells are new.
Access Roads (miles)	0.75	13.6	New roads for new wells.
CO_2 Distribution Piping (miles)	0.02	4.1	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	35 tpd	2,750 tpd	Based on CONSOL and Allison projects, respectively
Total Average CO_2 Injected (MT/year)	11,590	910,600	Converted to Metric Tons and Multiplied tpd by 365
Wastewater Storage Capacity	500 gallons	10,000 gallons	(Reeves, 2002)
Wastewater Generation (gal/hr)	2.98	59.5	Assume storage capacity is a weekly quantity.
Personnel (Operations)	1 per shift	2 per shift	Minimum based on project being automated system
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00007	0.006	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.003	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	7.3	576.7	AP-42, Section 1.3, Sept. 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.052	AP-42, Section 1.3, Sept. 1998. Emission factor = 2 lb/1000 gal.
Nitrogen Oxides (NO_f) (lb/hr)	0.007	0.517	AP-42, Section 1.3, Sept. 1998. Emission factor = 20 lb/1000 gal.
Carbon Monoxide (CO) (lb/hr)	0.002	0.129	AP-42, Section 1.3, Sept. 1998. Emission factor = 5 lb/1000 gal.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.014	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.556 lb/1000 gal.
Distillate Fuel Usage (gal/yr)	2,884	226,560	Calculated from required energy of heating unit and based on 8,760 hours per year. (Total usage for injection wells.)
Well Drilling Cuttings	3,492 cu.ft.	34,920 cu.ft.	873 cu. ft. per well. Based on 8-inch diameter well with a maximum depth of 2,500 feet.

2.5.5.6 Underground Injection Regulations

CLASS II WELLS. Those wells are utilized for injection for the purpose of: a) enhanced recovery of oil and gas; b) injection for storage of hydrocarbons liquid, at standard temperature and pressure; and c) the disposal of fluids which are brought to the surface in connection with natural gas storage operations or conventional production of oil and gas. Produced water may be commingled with waste waters from gas plants that are an integral part of production operation, unless those waters are classified as a hazardous waste at the point of injection. This does not include waste fluids from CO_2 production plants.

Conditions for Operation:

- New injection wells require a Permit for construction or conversion.
- An existing hydrocarbon storage or enhanced recovery well may be authorized by rule for the life of the well.
- Permits are issued for a limited period of time, that may be up to the operating life of the facility.
- New injection wells must be tested for mechanical integrity prior to operation.
- Once in operation, injection wells must have a mechanical integrity test at least once every five years.
- Existing rule authorized injection wells, which have had the tubing disturbed (workover), must have a pressure test to demonstrate mechanical integrity.
- Injection pressure shall not exceed that which would initiate and/or propagate fractures in the confining zone adjacent to a USDW.
- A review of the Permit is required at least once every five years, including review of the most recent mechanical integrity test.
- Area Permits are allowed for wells within the same well field, project or formation operated by a single owner or operator.
- Area of review for newly permitted injection wells is a minimum of 1/4 mile radius. This radius will be greater if the radius of endangering influence is found to exceed the fixed radius.
- Authorization by rule is granted for existing enhanced recovery wells subject to applicable construction, operating, reporting, monitoring, plugging, and financial assurance requirements listed in 40 CFR 144.28. Successful mechanical integrity tests must be conducted at least once every five years30.
- Emergency Permits are allowed if they meet the stipulations of 40 CFR 144.34..
- Operator must conduct monitoring of injection pressure, flow rate, and volume. Continuous monitoring may, in specific situations, be required.

Monitoring Requirements:

- The operator must obtain a sample of the injection fluid and analyze it for specified parameters at least once within the first year of authorization, and thereafter when changes are made to the injection fluid.
- The operator shall observe the injection pressure, flow rate, and cumulative volume at least weekly for SWD wells; monthly for ER wells; and daily for HC and cyclic steam wells. At least one observation of each of the above parameters is to be recorded at intervals no greater than 30 days.
- The operator must perform a mechanical integrity test (MIT) on the well at least once every five (5) years during the life of the well, and following any workover operation.

Reporting Requirements:

- If a well is temporarily abandoned (TA), the operator must notify the UIC Director notification within 30 days. A well may remain TA for a period of two (2) years, after which the operator must plug and abandon the well unless an extension is requested and subsequently granted by the UIC Director. An extension will only be granted if the operator can demonstrate that no endangerment to USDWs will take place during the period of the TA.
- The operator must report any noncompliance with UIC regulations orally to EPA within 24 hours of discovery and in writing within five (5) days.
- Submit an Annual Disposal/Injection Well Monitoring Report (EPA Form 7520-11 or State equivalent) summarizing observations of injection pressure and cumulative volume. Submit the report to the UIC Director by January 31 of each year covering the observations for the previous year. This requirement may be different for permitted wells; refer to the permit for appropriate date and requirements.
- If a change of ownership occurs for rule-authorized wells, the operator must notify EPA within 30 days of such transfer. Permitted wells require 30 days notice in advance of the proposed transfer date. An Application to Transfer Permit (EPA Form 7520-7or State equivalent).
- Notify the UIC Director of company change of address at least 15 days prior to the effective date.
- Submit Well Rework Record (EPA Form 7520-12 or State equivalent) within 60 days of any well workover.
- Notify EPA at least 30 days prior to performing a mechanical integrity test (MIT). A shorter notice is permissible if sufficient time is allotted for EPA to witness the test. The operator must provide the UIC Director with test results within 30 days, unless a MIT failure occurs (pressure change of 10 percent or greater within 30 minutes), in which case notification must be within 5 days.
- Notify the UIC Director at least 45 days prior to initiating plugging and abandonment of a well. A shorter notice is permissible if sufficient time is allotted for the UIC Director to witness the operation.
- Submit a Plugging Record (EPA Form 7520-13 or State equivalent) within 60 days of plugging and abandonment of a well, specifying the manner in which the well was plugged.

Due to the increased use of lateral drilling to recover coalbed methane, some states are revising their field rules and permitting processes for coalbed methane wells. For example, some current rules may require notification of adjacent owners within a certain distance of a well head (surface location). Rules are changing to specify horizontal distance from any portion of the well, including laterals.

2.5.5.7 Best Management Practices for ECBM

In April 2002, DOE sponsored a "Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin" (DOE, 2002). Although this handbook is location-specific and does not pertain solely to enhanced coal bed methane recovery with injection of CO_2, many of the BMPs in this handbook could minimize environmental impacts associated with ECBM. A summary of general BMPs is provided below:

- Determine if a beneficial use of recovered groundwater can be applied (such as use in dust suppression, water for livestock, creation of fish ponds, or reinjection to recharge aquifers)
- Minimize construction of new roads and utility corridors by utilizing existing networks or placing new utilities and roads within the corridor.

- Use local terrain, noise reduction technology and camouflage to minimize impacts for both noise and visual impairments.
- Use electric and hydraulic motors to operate pumps and compressors to reduce air emissions. Use produced methane to power pumps since its combustion results in few emissions than diesel or gasoline.
- Properly re-vegetate disturbed areas, re-introducing impacted native species where necessary. Stockpile topsoil for use in reclamation of construction sites.
- Institute a visual monitoring program to identify and remove noxious weeds that may be introduced during the exploration through production phase.
- Plug dry holes and wells in accordance with BLM and/or state requirements (DOE, 2002).

2.5.6 Enhanced Oil Recovery Geologic Sequestration Model Project

These model projects were developed to evaluate the impacts of geologic sequestration in oil formations as a part of Enhanced Oil Recovery (EOR) operations. Two options are evaluated. The first option evaluates sequestration of CO_2, and the second evaluates co-sequestration of CO_2 and hydrogen sulfide (H_2S). These processes are also referred to as EOR flooding. The EOR formation sequestration model projects would consist of transporting the gas stream on site from a nearby source, heating and regulating the gas stream pressure as necessary, and injecting the gas stream into the oil formation.

CO_2 is miscible with oil, and, once dissolved, causes the oil to become less viscous and more mobile. Through EOR, an additional 5 to 20 percent of oil is recovered (Stevens, et. al., 2000).

The following sections, which describe the model project, include the following elements:

- General design and operating parameters, including Monitoring, Mitigation, and Verification (MM&V);
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.6.1 Case A – Sequestration of CO_2

The first CO_2 flood occurred in 1972 in Texas, and since has grown into a widely-used practice nationwide and around the world to enhance the recovery of oil. Over 70 CO_2-EOR projects are currently active in the U.S.. Therefore, the technology to operate EOR formation CO_2 sequestration projects has been well developed. These projects have all operated with appropriate permits and approvals, as applicable by their respective states, including completing the NEPA review process and acquiring environmental permits, such as an air quality permit.

2.5.6.1.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of a few existing projects of CO_2 injection into oil formations. Six of the many existing commercial-sized projects were reviewed for this model project. These six are the Weyburn Field Project (Weyburn) in the Williston Basin oilfield in Weyburn, Saskatchewan; the Rangely Weber Field Project (Rangely) in Colorado; the Scurry Area Canyon Reef Operators Committee (SACROC) Field Project in the Permian Basin in Texas; the Wasson Denver Field Project in the Permian Basin in Texas; the PetroSource Energy field in Texas (PetroSource) which is owned by Riata Energy; and Denbury Resources Little Creek field in Mississippi (Denbury).

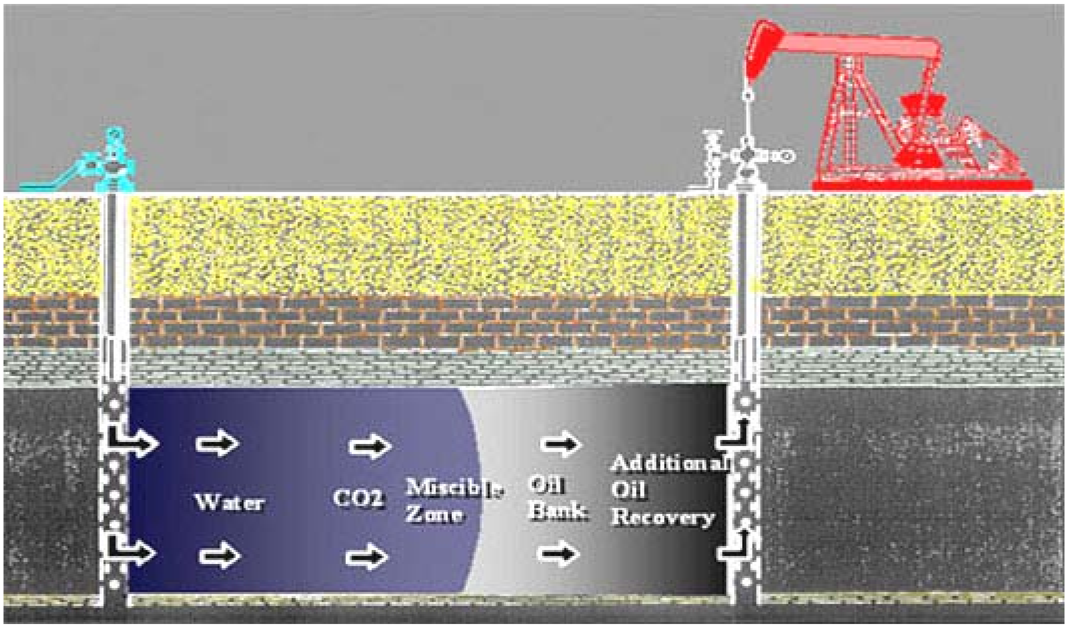
Descriptions of the model project parameters are included in Table 2-22. CO_2 injection at Weyburn averages 120 million standard cubic feet per day (MMscfd), 21 percent of which was recycled back from the production wells. Some of the CO_2 injected for EOR purposes is co-produced as associated gas or entrained with the oil. Because the CO_2 has a significant delivery cost, and incremental value to EOR operations, most CO_2 injection EOR operations include gas capture/recovery, separation, and reinjection of the CO_2 as a "recycle" stream.

CO_2 injection at Rangely peaked at 180 MMscfd and now operates at 60 MMscfd. SACROC also maintains an average injection rate of 60 MMscfd. Wasson Denver's CO_2 current injection rate is 320MMscfd (down from it previous 10-year long-term injection level of 426 MMscfd). CO_2 injection at PetroSource averages 37 MMscfd. Denbury maintains an average injection rate of 142 MMscfd. To ensure the model project encompasses injection rates similar to the commercial projects, the following range of CO_2 daily average injection rates were used: 1.17 MMscfd as a minimum from one well and 42.1 MMscfd as a maximum from thirty-six wells. These minimum and maximum rates are based on Wasson Denver injectivity rates (per injection well). For EOR operations, CO_2 is injected in its minimum supercritical state [greater than 1087 psi (6.9 MPa) and 88^{o}F (31^{o}C)] (EPRI, 1999).

For a field validation project, or a potentially larger pilot project, the number of injection wells would range from 1 to 36, the minimum of which is based on the average of the five smallest U.S. CO_2 EOR field projects (EPRI, 1999). The maximum is based on PetroSource. All injection wells would be new construction. The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 2 and 115 production wells would be used for oil production. Six wells for the minimum case are assumed to be existing wells, and of the 115 wells in the maximum case, at least half (or 58 wells) are assumed to be existing, with the remaining maximum of 57 being new construction. Between 1 and 20 new monitoring wells would be used for various MM&V requirements. The maximum number of production wells is based on the ratio of production to injection wells for the Rangely, Weyburn, and SACROC projects, with the minimum based on small U.S. CO_2 EOR projects. The number of monitoring wells is also estimated based on the Rangely, Weyburn, and SACROC projects. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the oil formation, as well as other hydrogeologic parameters that may indicate undesirable leakage of fluids from the formation. Figure 2-10 illustrates the typical configuration of CO_2 flooding using injection and production wells.

Depending on the depth of the oil formation, wells may extend from approximately 2,000 feet to 7,000 feet in depth. The ranges for the well depths are based on information from the Petroleum Technology Transfer Council website (www.pttc.org) and the CO_2 Norway website (www.co2.no).

A range of 0.5 mile to 11 miles of new 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 11 miles is assuming the distribution lines would begin at one central location and distribute out to three main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. Injection wells are a maximum of 1,600 feet apart. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.



Source: CO_2 Norway, 2007.

Figure 2-10. CO_2 Flooding

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (EPRI, 1999). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A pump, potentially a booster pump, would regulate the injection pressure and flow rate. A water injection pump will likely be required as well (Figure 2-11). A pipeline of recycled CO_2 from the production wells would also connect to the compressor or injection well.

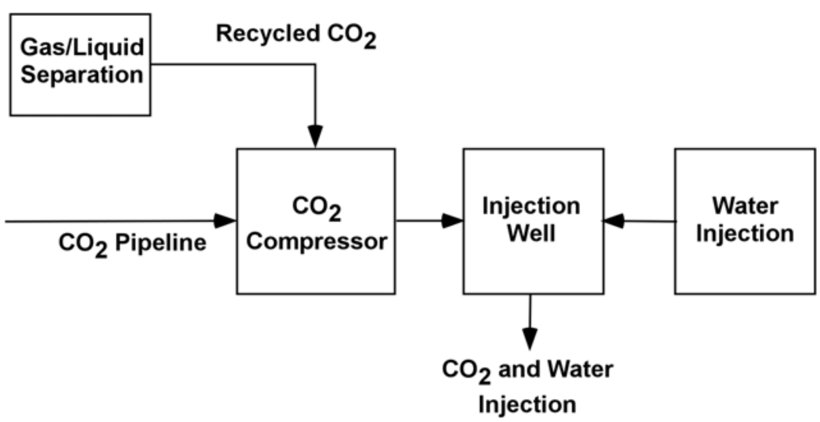


Figure 2-11. CO_2 Injection Well EOR Surface Configuration

For a model project with the maximum number of injection and production wells, the surface configuration for an oil production well would consist of the well and a multiphase pump to move multiphase mixtures to a centralized production facility. This facility would separate CO_2, oil and water, and distribute the non-petroleum liquids for recirculation or to storage tanks. For a minimum size model project, the production well site would potentially also contain smaller separation, gas compression, and tank storage capacities, rather than a centralized production facility. A water disposal well would also be required to pump separated water back into the ground (EPRI, 1999).

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the oil formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. Monitoring during and after injection would also include produced fluids (oil and water), produced gas (natural gas, condensable hydrocarbons, CO_2), soil gas sampling, geophysical measurements, and well logs.

2.5.6.1.2 Utility Requirements

Electricity will be required to operate multiple site operations. The major power demand operations include pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. Total electric power capacity for CO_2-EOR operations in the U.S. is estimated at about 963,000 horsepower (hp) or 788 megawatts (MW) (EPRI, 1999). Based on total U.S. 2000 CO_2 flooding volumes of 30 million tons / year (Stevens et al., 2000), annual electricity usage rates for CO_2 EOR operations is estimated at 1.86 hp / MMscf or 1.387 KW/MMscf.

2.5.6.1.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. For example, if the compressor used either natural gas or diesel fuel for operations, minor quantities of hazardous air pollutants and criteria pollutants such as nitrogen oxides and carbon monoxide would be emitted. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Once the produced fluids (oil and water) are separated, the non-potable water will require disposal. Typically, an underground injection well at the project site is used to dispose of the non-potable, saline produced water.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the petroleum “trap”, which created the formation.

Well drilling cuttings would require collection and management. An estimated maximum 2,400 cubic feet of cuttings collection would occur at each new well. This estimate is based on an 8-inch diameter well with a maximum depth of 7,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.6.1.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 135 to 2,880 acres. A minimum distance between injection and production wells would be 500 feet and the maximum distance between injection wells would be 1,600 feet. The maximum distance is based on the Rangely Weber and Wasson Denver projects.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated and only one person would be required full time. For a larger acreage, potentially three people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction, and operation.

2.5.6.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For a site maximum area of 2,880 acres of land, a maximum of 43 miles of new dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 686 acres would be required for roads and equipment locations. This value is based on clearing 43 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of nineteen equipped with appropriate machinery including front-end loaders and chippers would take about 30 days (4600 man-hours) to prepare the site. The pilot scale facility would require approximately 135 acres of land, 15 of which would be cleared, and 1 mile of access roads.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.6.2 Case B – Co-Sequestration of Sour Gas (CO_2 and H_2S)

2.5.6.2.1 General Design and Operating Parameters

To ensure the model project encompasses injection rates similar to the commercial projects, the following range of CO_2 daily average injection rates were used: 1.17 MMscfd as a minimum from one well and 42 MMscfd as a maximum from thirty-six wells. These minimum and maximum rates are based on Rangely and SACROC. For EOR operations, CO_2 is injected in its minimum supercritical state [greater than 1087 psi (6.9 MPa) and 88°F (31°C)] (EPRI, 1999). Based on the Gas Research Institute Topical Report (GRI, 1991), the maximum weight percent (wt %) of H_2S in the gas stream would be 25. The minimum would be 2 wt%.

For a field validation project, or a potentially larger pilot project, the number of injection wells would range from 1 to 36, the same as that of Case A: Sequestration of CO_2 EOR. All injection wells would be new construction. The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 6 and 115 production wells would be used for oil production. Two wells for the minimum case are assumed to be existing wells, and of the 115 wells in the maximum case, at least half (or 58 wells) are assumed to be existing, with the remaining maximum of 57 being new construction. Between 1 and 20 monitoring wells would be used for various MM&V requirements. The number of production wells is based on the ratio of production to injection wells for the Rangely, Weyburn, and SACROC projects. The number of monitoring wells is also estimated based on the Rangely, Weyburn, and SACROC projects. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the oil formation, as well as other hydrogeologic parameters that may indicate undesirable leakage of fluids from the formation.

Depending on the depth of the oil formation, wells may extend from approximately 2,000 feet to 7,000 feet in depth. The ranges for the well depths are based on information from the Petroleum Technology Transfer Council website (www.pttc.org) and the CO_2 Norway website (www.co2.no).

A range of 0.5 mile to 11 miles of 4-inch piping would be required to transport the CO_2 to individual wells on site. This maximum of 11 miles is assuming the distribution lines would begin at one central location and distribute out to three main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. As discussed later, injection wells are a maximum of 1,600 feet apart. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (EPRI, 1999). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A pump, potentially a booster pump, would regulate the injection pressure and flow rate. A water injection pump will likely be required as well. A pipeline of recycled CO_2 from the production wells would also connect to the compressor or injection well.

For a model project with the maximum number of injection and production wells, the surface configuration for an oil production well would consist of the well and a multiphase pump to move multiphase mixtures to a centralized production facility. This facility would separate CO_2, oil and water, and distribute the non-petroleum liquids for recirculation or to storage tanks. For a minimum size model project, the production well site would potentially also contain smaller separation, gas compression, and tank storage capacities, rather than a centralized production facility. A water disposal well would also be required to pump separated water back into the ground (EPRI, 1999).

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the oil formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. Monitoring during and after injection would also include produced fluids (oil and water), produced gas (natural gas, condensable hydrocarbons, and CO_2), and soil gas sampling.

2.5.6.2.2 Utility Requirements

Electricity will be required to operate multiple site operations. The major power demand operations include pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. Total electric power capacity for CO_2-EOR operations in the U.S. is estimated at about 963,000 horsepower (hp) or 788 megawatts (MW) (EPRI, 1999). Based on total U.S. 2000 CO_2 flooding volumes of 30 million tons / year (Stevens et al., 2000), annual electricity usage rates for CO_2 EOR operations is estimated at 1.86 hp / MMscf.

2.5.6.2.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. For example, if the compressor used either natural gas or diesel fuel for operations, minor quantities of hazardous air pollutants and criteria pollutants such as nitrogen oxides and carbon monoxide would be emitted. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Once the produced fluids (oil and water) are separated, the non-potable water will require disposal. Typically, an underground injection well at the project site is used to dispose of the non-potable, saline produced water.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the petroleum "trap", which created the formation.

Well drilling cuttings would require collection and management. An estimated maximum 2,400 cubic feet of cuttings collection would occur at each new well. This estimate is based on an 8-inch diameter well with a maximum depth of 7,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.6.2.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 135 to 2,880 acres. A minimum distance between injection and production wells would be 500 feet and the maximum distance between injection wells would be 1,600 feet. The maximum distance is based on the Rangely Weber and Wasson Denver projects.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated and only one person would be required full time. For a larger acreage, potentially three people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction, and operation.

2.5.6.2.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For a site maximum area of 2,880 acres of land, a maximum of 43 miles of dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 686 acres would be required for roads and equipment locations. This value is based on clearing 43 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of nineteen equipped with appropriate machinery including front-end loaders and chippers would take about 30 days (4600 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-22. Case A - Sequestration of CO_2 - EOR Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Oil Formation Depth	2,000 feet	7,000 feet	Based on CO_2 Norway and PTTC websites
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	135	2,880	Based on the number of wells and the distance between
Distance btw Wells	500 feet	1,600 feet	Maximum based on injection well to production well spacing; maximum based on average of Rangely Weber and Wasson Denver injection well to injection well spacing.
Injection Wells	1-2	36	Minimum based on average of 5 smallest U.S. CO2 EOR field projects. Maximum based on PetroSource. All wells are new.
Production Wells	6	115	Based on the ratio of production to injection wells for Weyburn, Rangely and SACROC. For minimum, wells are existing. For maximum, 50% (58 wells) are existing.
Observation / Monitoring Wells	1	20	Based on Weyburn, Rangely and SACROC projects. All wells are new.
Clearing (acres)	15	686	Minimum and maximum based on 1 mile and 43 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	1	43	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.5	11	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	1.17 MMscfd	42.1 MMscfd for 36 wells	Based on Wasson Denver long-term injectivity.
Total Average CO_2 Injected (MT/year)	22,498	809,209	Converted MMscfd to MT/year using Ideal Gas Law
Personnel (Operations)	1 per shift	3 per shift	Minimum based on model project being automated system
Well Drilling Cuttings	4,800 cu.ft	268,800 cu.ft	Based on 8-inch diameter well with a maximum depth of 7,000 feet.
Utility Requirements	0.32 kW	65.2 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf

Table 2-23. Case B - Sequestration of CO_2/H_2S EOR Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Oil Formation Depth	2,000 feet	7,000 feet	Based on CO_2 Norway and PTTC websites
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	135	2,880	Based on the number of wells and the distance between
Distance btw Wells	500 feet	1,600 feet	Maximum based on injection well to production well spacing; maximum based on average of Rangely Weber and Wasson Denver injection well to injection well spacing.
Injection Wells	1	36	Minimum based on average of 5 smallest U.S. CO2 EOR field projects. Maximum based on PetroSource. All wells are new.
Production Wells	6	115	Based on the ratio of production to injection wells for Weyburn, Rangely and SACROC. For minimum, wells are existing. For maximum, 50% (58 wells) are existing.
Observation / Monitoring Wells	1	20	Based on Weyburn, Rangely and SACROC projects. All wells are new.
Clearing (acres)	15	686	Minimum and maximum based on 1 mile and 43 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well (equipment locations).
New Access Roads (miles)	1	43	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.5	11	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average Sour Gas Injected	1.17 MMscfd	42.1 MMscfd for 36 wells	Based on Wasson Denver long-term injectivity.
Total Average Sour Gas Injected (MT/year)	22,498 tpy	809,209	Converted MMscfd to MT/year using Ideal Gas Law
CO_2 Injected (MT/year)	22,048	606,907	Based on minimum of 75 wt% and maximum of 98 wt%.
H_2S Injected (MT/year)	450	202,302	Based on minimum of 2 wt% and maximum of 25 wt%. Maximum wt% based on Gas Research Institute Topical Report (GRI, 1991).
Personnel (Operations)	1 per shift	3 per shift	Minimum based on model project being automated system
Well Drilling Cuttings	4,800 cu.ft	268,800 cu.ft	Based on 8-inch diameter well with a maximum depth of 7,000 feet.
Utility Requirements	1.62 kW	58.3 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf

2.5.7 Saline Formation Geologic Sequestration Model Projects

These model projects were developed to evaluate the impacts of geologic sequestration in saline formations. Two options are evaluated. The first option evaluates sequestration of CO_2, and the second evaluates co-sequestration of sour associated gas, CO_2 and hydrogen sulfide (H_2S). The saline formation sequestration model projects would consist of transporting the gas stream on site from a nearby source, heating and regulating the pressure of the gas stream, and injecting the gas stream into the saline formation.

The following sections, which describe the model projects, include the following elements:

- General design and operating parameters including Monitoring, Mitigation, and Verification (MM&V),
- Utility requirements,
- Environmental process discharge streams,
- Site requirements and operations, and
- Construction phase activities.

2.5.7.1 Case A – Sequestration of CO_2

The technology to operate saline formation CO_2 sequestration projects are currently in practice. CO_2 sequestration projects in saline formations have occurred in various locations worldwide. Within the U.S., CO_2 sequestration occurred in the Frio sandstone formation in Texas. Worldwide, CO_2 sequestration occurred in the South Nagaoka Gas Field in Nagaoka, Japan, and in the Sleipner Gas Field in the Norwegian North Sea. These projects have all operated with appropriate permits and approvals, as applicable by their respective countries. For example, the Frio project in Texas completed the NEPA review process and acquired environmental permits, such as an air quality permit.

2.5.7.1.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing projects of CO_2 injection into saline formations. The three existing projects that were reviewed are the Frio Brine Pilot Project (Frio) in the Frio sandstone formation in Texas, the Sleipner Gas Field (Sleipner) in the Norwegian North Sea, and the South Nagaoka Gas Field (Nagaoka) in Nagaoka, Japan. The Frio and Nagaoka projects are onshore, small-scale pilot R&D size projects, while Sleipner is an off-short, full-scale commercial sized project.

Typical model project parameters are summarized in Table 2-24. CO_2 injection at Nagaoka averaged from 20 tons/day to 40 tons/day between July 2003 and November 2004. CO_2 injection at Frio averaged at 178 tons/day over the nine day injection period in October 2004. Sleipner, a full scale project, began CO_2 injection in October 1996 and continues to maintain an average daily injection rate of 2,800 tons of CO_2 to date (Statoil, 2004). To ensure the model project encompasses injection rates similar to a commercial project, the following range of CO_2 daily injection rates would be used: 40 tons/day (13,140 MT/year) as a minimum from one well for a pilot-scale, R&D sized project and 2,800 tons/day (927,100 MT/year) as a maximum from three wells for a full-scale, commercial size project (Note: As a point of comparison, a typical 200 MW coal-fired power plant has CO_2 emissions on the order of 4,000 tons/day).

The number of injection wells would range from 1 to 20, of which the minimum number is based on both the on-shore pilot projects and the injection rate based on Nagaoka. In part because of its off-short location and well requirements, Sleipner has only a single injection well. Therefore, for the maximum number of wells for a commercial-scale on-shore saline formation project, it was assumed that the injectivity of a saline formation would be roughly twice that of an EOR formation or 2.34

MMscfd/injector. At 2740 tons per day or 47.2 MMscfd total CO_2 injection, this results in a maximum of 20 injection wells.

Table 2-24. Case A - Sequestration of CO_2 - Saline Formation Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Saline Formation Depth	3,000 feet	6,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Saline Formation Thickness	160 feet	1,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	92	2,750	Based on the number of wells and the distance between
Distance btw Wells	500 feet	2000 feet	Minimum based on Frio and Nagaoka projects. Maximum based on extrapolation of Sleipner projections.
Injection Wells	1	20	Based on Frio, Nagaoka, and Sleipner Projects for minimum. Maximum based on twice the EOR injectivity. Wells are new.
Observation / Monitoring Wells	1	8	Based on minimum of 1, but potentially 8 for larger acreage. Wells are new.
Well Drilling Cuttings	4,200 cu.ft.	58,800 cu.ft.	Based on 8-inch diameter well with a maximum depth of 6,000 feet.
Clearing (acres)	9	291	Maximum based on 23 miles of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	0.3	23	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	7.6	Maximum based on 3 distribution lines from central point between injection wells with minimum distances of 500 feet and 2000 feet respectively. All new piping, which will be placed in new road right-of-ways.
Total Average CO_2 Injected (MT/day)	36	2,490	Based on Nagaoka and Sleipner Projects, respectively
Total Average CO_2 Injected (MT/year)	13,140	909,100	Multiplied by 365
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being an automated system
Distillate Fuel Usage	3,295 gal/yr	76,893 gal/yr	Calculated from required energy of heating unit and based on 8,760 hours per year.
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00008	0.002	AP-42, Section 1.3, September 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.001	AP-42, Section 1.3, September 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	8.4	195.7	AP-42, Section 1.3, September 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.018	AP-42, Section 1.3, September 1998. Minimum emission factor (2 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (2 lb/1000 gal) for Boilers >1 MMBtu/hr.
Nitrogen Oxides (NO_f) (lb/hr)	0.008	0.211	AP-42, Section 1.3, September 1998. Minimum emission factor (20 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (24 lb/1000 gal) for Boilers >1 MMBtu/hr.
Carbon Monoxide (CO) (lb/hr)	0.002	0.044	AP-42, Section 1.3, September 1998. Minimum emission factor (5 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (5 lb/1000 gal) for Boilers >1 MMBtu/hr.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.005	AP-42, Section 1.3, September 1998. Emission factor = 0.556 lb/1000 gal.

The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 1 and 8 monitoring wells would be installed for various MM&V requirements. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the saline formations. All injection and monitoring wells would be new construction.

Depending on the depth of the saline formation, wells may extend from 3,000 to 6,000 feet in depth, with the formation ranging from 160 feet to 1,000 feet thick. The ranges for the well depths and the saline formation thickness used in the model projects are based on all three existing field projects (Note: Some of the Regional Partnerships are in the process of evaluating potential sequestration opportunities at even greater depths, i.e., up to 10,000 feet or deeper).

A range of 0.1 mile to 7.6 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 7.6 miles is assuming the distribution lines would begin near a location central to the twenty injection wells and distribute out to each injection well. As discussed later, injection wells are a minimum of 500 feet from any observation well or injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe. All piping would be new construction.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (Hovorka et al., 2003; Kikuta et al., 2004). At least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. A heating unit would be anticipated as the CO_2 would require temperature control. The heating unit would either use natural gas, diesel fuel, or electricity for operations. Inline monitors will ensure the CO_2 is injected at the appropriate temperature. A Supervisory Control and Data Acquisition (SCADA) system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup.

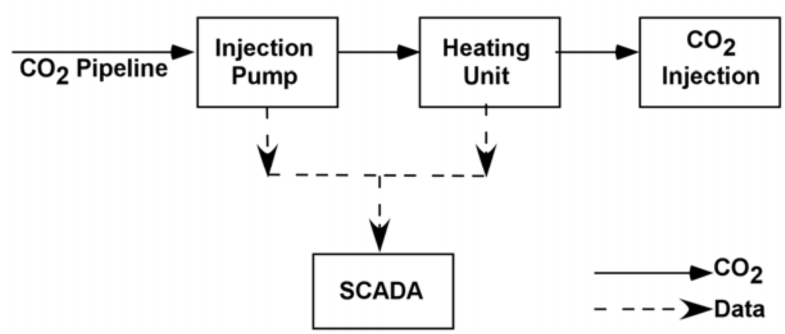


Figure 2-12. CO_2 Injection Well Saline Formation Surface Configuration.

Figure 2-12 shows the flow diagram of the surface configuration.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the saline formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, wireline logging, measurement of in-situ temperature and pressure, and electromagnetic imaging (Kikuta et al., 2004; Techline, 2004).

2.5.7.1.2 Utility Requirements

Utility requirements for the model project include fuel usage and electricity. Fuel would be trucked on site for the injection well heating unit. No additional on-site fuel storage is anticipated. Fuel usage would range from approximately 3,295 gallons per year to 76,893 gallons per year for the minimum and maximum scenarios. Electricity would be required to operate the injection pumps and potentially the heating unit.

2.5.7.1.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Usage of distillate fuel is assumed for a conservative estimate of air emissions.

Table 2-24 shows air emissions for the minimum and maximum scenarios. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the caprock seal.

Well drilling cuttings would require collection and management. An estimated maximum 2,100 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 6,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.7.1.4 Site Requirements and Operations

It is assumed that the full-scale, commercial sized model project would be co-located with a CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the necessary CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale field validation R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 92 to 2,750 acres. A minimum distance between injection and observation wells would be 500 feet (NETL, 2003; Kikuta et al., 2004). Depending on the formation properties, injection wells could be up to 2500 feet apart from each other (Myer, 2005).

For Sleipner's 2,740 tons per day single CO_2 injector, pre-injection modeling indicated CO_2 movement of 10,000 feet from the injection point in 20 years; 3-year post-injection measurements indicated a 3,500 by 5,000 foot CO_2 bubble, with structural trap containment after 20 years projected at a maximum of 40,000 feet from the injection point (Statoil, 2004). For this onshore model project's 20 CO_2 injectors, each with 5 percent of the Sleipner injection rate, a 2,000 foot injection well to injection well spacing was assumed.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.7.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 291 acres would be required for roads and equipment locations. For 2,750 acres of land, a maximum of 23 miles of dirt and/or gravel access roads are anticipated. A crew of twenty equipped with appropriate machinery including front-end loaders and chippers would take about 20 days (3,200 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of about 20 – 50 construction personnel would require between 3 – 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.7.2 Case B – Co-Sequestration of Sour Gas (CO_2 and H_2S)

The technology to operate saline formation CO_2 and H_2S co-sequestration projects are currently in practice, although the projects relate to disposal by injection, rather than sequestration. CO_2 and H_2S co-sequestration projects in saline formations have occurred in various locations worldwide, specifically in the Alberta Basin in western Canada. By the end of 2003, 48 sites in western Canada, 20 sites in the U.S., and additional locations in the Middle East and North Africa were injecting acid gas into deep saline formations and depleted oil formations.

2.5.7.2.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing projects of injection into saline formations, as specified in the Case A description.

Typical model project parameters are summarized in Table2-25. To ensure the model project encompasses injection rates similar to a commercial project, the following range of daily injection rates would be used: 36 MT/day (13,140 MT/year) as a minimum from one well and 2,490 MT/day (909,100 MT/year) as a maximum from three wells. Based on the Gas Research Institute Topical Report (GRI, 1991), the maximum weight percent (wt%) of H_2S in the gas stream would be 25 percent. The minimum would be 2 wt%. Therefore, the anticipated maximum injection rates for CO_2 and H_2S are 681,800 MT/year and 227,300 MT/year, respectively.

Table 2-25. Case B - Co-Sequestration of CO_2/H_2S - Saline Formation Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Saline Formation Depth	3,000 feet	6,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Saline Formation Thickness	160 feet	1,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Transport Sour Gas to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	92	2,750	Based on the number of wells and the distance between
Distance between Wells	500 feet	2,000 feet	Minimum based on Frio and Nagaoka projects. Maximum based on extrapolation of Sleipner projections.
Injection Wells	1	20	Based on Frio, Nagaoka, and Sleipner Projects for minimum. Maximum based on twice the EOR injectivity. Wells are new..
Observation / Monitoring	1	8	Based on minimum of 1, but potentially 8 for larger acreage. All

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Wells			wells are new.
Well Drilling Cuttings	4,200 cu.ft.	58,800 cu.ft.	Based on 8-inch diameter well with a maximum depth of 6,000 feet.
Clearing (acres)	9	291	Maximum based on 23 miles of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	0.3	23	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	7.6	Maximum based on 3 distribution lines from central point between injection wells with minimum distances of 500 feet and 2000 feet respectively. All new piping, which will be placed in new road right-of-ways.
Total Average Sour Gas Injected (MT/day)	36	2,490	Based on Nagaoka and Sleipner Projects, respectively
Total Average Sour Gas Injected (MT/year)	13,140	909,100	Multiplied tpd by 365
CO_2 Injected (MT/year)	12,877	681,825	Based on minimum of 2 wt% H_2S/ 98 wt%CO_2 and maximum case of 25 wt% H_2S/ 75 wt% CO_2, respectively.
H_2S Injected (MT/year)	263	227,275	Based on a minimum of 2 wt% and maximum 25 wt%. Maximum wt % based on Gas Research Institute Topical Report (1991).
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being an automated system
Distillate Fuel Usage	3,295 gal/yr	76,893 gal/yr	Calculated from required energy of heating unit and based on 8,760 hours per year.
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00008	0.002	AP-42, Section 1.3, September 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.001	AP-42, Section 1.3, September 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	8.4	195.7	AP-42, Section 1.3, September 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.018	AP-42, Section 1.3, September 1998. Minimum emission factor (2 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (2 lb/1000 gal) for Boilers >1 MMBtu/hr.
Nitrogen Oxides (NO_f) (lb/hr)	0.008	0.211	AP-42, Section 1.3, September 1998. Minimum emission factor (20 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (24 lb/1000 gal) for Boilers >1 MMBtu/hr.
Carbon Monoxide (CO) (lb/hr)	0.002	0.044	AP-42, Section 1.3, September 1998. Minimum emission factor (5 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (5 lb/1000 gal) for Boilers >1 MMBtu/hr.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.005	AP-42, Section 1.3, September 1998. Emission factor = 0.556 lb/1000 gal.

The number of injection wells would range from 1 to 20. The majority of other project data (site acreage, miles of access roads, etc.) is based off of the number of injection wells. Between 1 and 8 monitoring wells would be installed for various MM&V requirements. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 and H_2S injected in the saline formations. All injection and monitoring wells would be new construction.

Depending on the depth of the saline formation, wells may extend from 3,000 to 6,000 feet in depth, with the formation ranging from 160 feet to 1,000 feet thick. The ranges for the well depths and the saline formation thickness are based on all three existing field projects.

A range of 0.1 mile to 7.6 mile of 4-inch piping would be required to transport the CO_2 and H_2S to individual wells on site. This maximum of 0.3 mile is assuming the distribution lines would begin near a location central to the three injection wells and distribute out to each injection well. As discussed later, injection wells are a minimum of 500 feet from any observation well or injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for CO_2 and H_2S injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for an injection well would consist of the following equipment (Hovorka et al., 2003; Kikuta et al., 2004). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. At least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. A heating unit would be anticipated as the CO_2 and H_2S would require temperature control. The heating unit would either use natural gas, diesel fuel, or electricity for operations. Inline monitors will ensure the CO_2 and H_2S is injected at the appropriate temperature. A SCADA system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup. The footprint for the CO_2 and H_2S injection surface configuration is anticipated to be about 150 square feet.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the saline formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, wireline logging, measurement of in-situ temperature and pressure, and electromagnetic imaging (Kikuta et al., 2004; Techline, 2004).

2.5.7.2.2 Utility Requirements

Utility requirements for the model project include fuel usage and electricity. Fuel would be trucked on site for the injection well heating unit. No additional on-site fuel storage is anticipated. Fuel usage would range from approximately 3,295 gallons per year to 76,893 gallons per year for the minimum and maximum scenarios. Electricity would be required to operate the injection pumps and potentially the heating unit.

2.5.7.2.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Usage of distillate fuel is assumed for a conservative estimate of air emissions. Table 2-25 shows air emissions for the minimum and maximum scenarios. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the caprock seal.

Well drilling cuttings would require collection and management. An estimated maximum 2,100 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 6,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.7.2.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation

R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 92 to 2,750 acres. A minimum distance between injection and observation wells would be 500 feet (NETL, 2003; Kikuta et al., 2004).

CO_2 and H_2S injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 and H_2S injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.7.2.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 291 acres would be required for roads and equipment locations. For 2,750 acres of land, a maximum of 23 miles of dirt and/or gravel access roads are anticipated. A crew of twenty equipped with appropriate machinery including front-end loaders and chippers would take about 20 days (3,200 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.8 Basalt Formation Geologic Sequestration Model Project

This model project was developed to evaluate the impacts of geologic sequestration in basalt formations. The basalt formation geologic sequestration model project would consist of transporting the CO_2 gas stream on-site from a nearby source and injecting the gas stream into the basalt formation. The technology to install and operate basalt formation CO_2 sequestration projects is similar to that associated with EOR and saline formation geologic sequestration applications. However, with the exception of a very small, short term (i.e., several day) CO_2 injection field experiment (Matter, 2005), as of the 4th quarter 2005 there have been no CO_2 sequestration field projects in basalt formations conducted anywhere in the world. Thus, the design basis for this model project is largely conceptual and substantially based on the extensive characterization work by the U.S. DOE of the Columbia River Basalt Group (CRBG) and the U.S. Geological Survey in the U.S. Pacific Northwest (BSRCSP, 2005; USGS, 2005). Additional descriptions of current sequestration technologies are discussed in Section 2.2.

Basalt is a dark-colored igneous rock composed chiefly of aluminum silicate minerals and has fine-grained or glassy texture. The major elements in basalt are silica, aluminum, oxygen, calcium, iron and magnesium. Extensive basalt formations that may be attractive for carbon sequestration occur in the Pacific Northwest, the Southeastern U.S., and in several other U.S. regions. Because of the very limited study of basalts for carbon sequestration, basic information on injectivity, storage capacity, and rate of conversion of gaseous CO_2 to solid carbonates is not available. Insufficient data have been generated from these experiments to permit reliable projections of CO_2 conversion rates under large-scale sequestration conditions. Information is also lacking on the ability of basalts from other parts of the U.S. to support *in-situ* mineralization reactions (NETL, 2004).

The basalt model project description below includes the following elements:

- General design and operating parameters including MM&V;
- Utility requirements;
- Environmental concerns;
- Site requirements and operations; and
- Construction phase activities.

2.5.8.1 General Design and Operating Parameters

Based on the available information, favorable sites for CO_2 injection into basalt may have formation characteristics comparable to those of the model saline formation site. Typical project parameters for the basalt model project are summarized in Table 2-26. The model project for basalt would have the following range of CO_2 annual injection rates: 3,000 tons per year (2,722 MT per year) for a small pilot project, and 500,000 tons per year (453,592 MT per year) for a commercial-scale project. Using injection well spacing comparable to commercial scale, multi-well onshore saline applications, results in a maximum of 12 injection wells, at 2400 feet spacing between wells. The number of injection wells would range from 1 to 12, with the minimum wells and injection rate based on 2 pilot projects planned, one in the CRBG and one in India (McGrail, 2005 and Kumar, 2005). The majority of other project data (site acreage, miles of access roads, etc.) are derived from the number of injection wells.

Between 3 and 10 monitoring wells would be needed for various MM&V requirements. If multiple wells were drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the basalt formation. All injection and monitoring wells would be new construction. Depending on the depth of the basalt formation, which the CRBG formation depth ranging from 3,000 to 12,000 feet, wells may extend from 3,000 to 5,000 feet in depth, with the Grande Ronde formation of the CRBG ranging from 500 feet to 8,000 feet in thickness (Reidel, 2002).

A range of 0.1 mile to 5.5 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 5.5 miles was based on the assumption that the distribution lines would begin near a location central to the four rows of three injection wells and distribute out to each injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe. All piping would be new construction.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment: at least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. Inline monitors will ensure the CO_2 is injected at the appropriate temperature. A Supervisory Control and Data Acquisition (SCADA) system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the basalt formation, deep groundwater, shallow aquifers, surface water, and gas monitoring. These activities are then continued during injection, and for extensive time periods following injection. MM&V technologies may include downhole vertical seismic tomography and profiling, wireline logging, downhole geochemical sampling, measurement of in-situ temperature and pressure, introduced tracers, and atmospheric monitoring.

2.5.8.2 Utility Requirements

Utility requirements for the model project include electricity. Electricity would be required to operate the injection pumps. These requirements are not expected to exceed those of EOR applications, so the EOR factor of 1.387 kW/MMscf was used here.

2.5.8.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Refer to the CO_2 Transport Model Project (see Section 2.5.4) description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Subsurface leakage of undesirable fluids from the injection well into shallower aquifers can result from inadequate annular well seals or damaged casing. Leakage of lower quality water or gas from the subsurface formation may also result from excessive injection pressures, either by hydrofracturing or by fluids escaping from the basalt formation along faults or fracture zones.

Well drilling cuttings would require collection and management. An estimated maximum 1,050 cubic feet of cuttings collection would occur at each 3,000-foot well. This estimate is based on an 8-inch diameter well. Consistent with local regulatory requirements, soils that are contaminated with hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.8.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information (Section 2.5.4). The site should range from approximately 60 to 2,600 acres. A minimum distance between injection and observation wells would be between 100 feet and 500 feet, respectively (NETL, 2003 and Kikuta, 2004); 400 foot spacing was selected. The maximum distance between commercial scale injection wells was estimated at 2,400 feet, approximately equal to that of the saline formation model project.

CO_2 injection would occur continuously with three shifts of operators. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.8.5 Construction Phase Activities

Site preparation activities prior to construction would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 166 acres would be required for roads and equipment locations. For 2,600 acres of land, a maximum of 11 miles of dirt and/or gravel access roads are anticipated. A crew of 15 equipped with appropriate machinery including front-end loaders and chippers would take approximately 30 days (3600 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, and utility tie-ins (electricity) would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures would be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-26 Basalt Formation Model Project Data Sheet

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Basalt Formation Depth	3,000 feet	12,000 feet	CRBG boreholes (8 total) stratigraphy data (Reidel, 2002).
Basalt Formation Thickness	500 feet	8,000 feet	Grande Ronde basalt formation of CRBG (Reidel, 2002).
Individual Basalt Flows Thickness	30 feet	300 feet	CRBG individual basalt flow thickness (Reidel, 2002).
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	59	2,600	Based on the number of wells and the distance between.
Distance Between Wells	400 feet	2,400 feet	Minimum based on injection/monitoring well spacing of EOR and saline single injection well pilot projects. Maximum based on that of saline formation injection well-to-injection maximum well spacing (i.e., 2000 – 2,500 feet).
Injection Wells	1	12	All wells are new.
Well Depth	3,000 feet	5,000 feet	Minimum based on 800-1200m target injection zone for Phase II pilot planned in CRBG. Maximum = ½ that of deep saline formations, as basalt available at shallower depths, higher Mg/Ca concentrations for mineralization reactions, and avoid porosity reductions at greater depths.
Observation / Monitoring Wells	3	10	All wells are new. Minimum based on preliminary plan for CRBG pilot. Maximum based on interior cell and 4-corner grid external monitoring well placement.
Clearing (acres)	16	166	Minimum and maximum based on 0.5 mile and 11 miles, respectively, of 75' right-of-ways for new roads, plus 3 acres per new well (injection and monitoring) for equipment locations.
New Access Roads (miles)	0.5	11	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	5.5	Based on number of injection wells and distance between. Maximum based on 2 distribution lines from central point between injection wells with maximum spacing. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	0.14 MMscfd	23.6 MMscfd for 12 wells	Ideal gas law mass-volume conversion.
Total Average CO_2 Injected	8.2 tpd	1,370 tpd	Average daily injection rate for total annual injection (based on 3,000 and 500,000 tons per year).
Total CO_2 Injected (MT/Year)	2,720	453,600	Minimum based on 2 pilots planned in U.S. Northwest and India (McGrail, 2005 and Kumar, 2005). Maximum project size = ½ that of other geologic sequestration technologies, due to lack of field project experience and development status.
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being automated system.
Well Drilling Cuttings	4,200 cu.ft	38,400 cu.ft	Based on 8-inch diameter well with a maximum depth of 3,000 to 5,000 feet, respectively.
Utility Requirements	0.19 kW	32.7 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf utility requirements of EOR projects.

2.5.9 Carbon Sequestration on Mined Lands Model Project (Reforestation)

In considering potential technologies and corresponding model projects for carbon sequestration, evaluating the impacts of two terrestrial sequestration approaches to sequestering CO_2 was selected as a model project. Long-lived forest stands act as natural carbon sinks for sequestering carbon in terrestrial systems over many years. The amount of CO_2 stored in a particular ecosystem can actually increase annually in correlation with biomass increases of the vegetation. The following processes described are generic in nature so as to be applicable to many regions of the country. The model project described below is based upon general standards for approximating how these projects can successfully sequester CO_2, as part of a reclamation program on mined lands.

One constraint to applying forestation/reforestation and no-till agriculture technologies in sequestering carbon is that the process is limited to areas where the climate and existing soils are suitable for this practice. For example, reforestation is not a feasible practice in the deserts of the Southwest U.S. where the annual rainfall is low and the vegetation (often low shrubs and cacti) is sparse and adapted to low moisture conditions. It is not that those areas cannot be revegetated or restored, but they will require a specific set of conditions and vegetation species, and are unlikely candidates for economical forestation/reforestation for sequestering CO_2. However, one of the attractions of this particular technology is that most regions of the U.S. are well suited for sequestration of CO_2 either by existing forest stands or re-vegetation.

The ability of a forest to sequester carbon is based on many factors. Descriptions of factors that could affect forest health and carbon sequestration are given in Section 4.2.3.8.

The following sections describe the basis for and characteristics of each of the two cases for the model project:

- General design and operating parameters of the model project;
- Environmental process discharge streams and benefits;
- Site requirements and operations;
- Installation/construction phase activities; and
- Monitoring, mitigation, and verification (MM&V).

2.5.9.1 Case A: Forestation on Mined Lands

Responsibility for terrestrial sequestration research is shared by many Federal agencies, and the DOE-NETL program coordinates activities in this area with the DOE Office of Science, U.S. Department of Agriculture, Environmental Protection Agency, and Department of Interior Office of Surface Mining, The scope of terrestrial sequestration options addressed in the DOE-NETL Carbon Sequestration Program is limited to the integration of energy production, conversion, and use with land reclamation. Specifically, this involves the reforestation and amendment of damaged soils. Field validation tests focus on improving the carbon storage of previously or abandoned mined land and optimizing land management practices. Current projects include demonstration of reforesting recently mined lands in Virginia, West Virginia, and Ohio and a smaller-scale demonstration integrating terrestrial sequestration with energy production, involving greater than 700 acres total of previously mined land. The focus is on enhancing the productivity of terrestrial ecosystems through the application of soil amendments, such as coal combustion byproducts, and biosolids from wastewater treatment facilities (NETL, 2004).

Much of the strip mining in the Eastern U.S. is on forested lands. Unfortunately, after mining most of these areas are restored as grasslands. However, much more carbon is stored in a hectare of forest than in a hectare of grasslands. Within the Appalachian coal region, there may be up to 400,000 hectares (1 million acres) of abandoned mined lands. These areas contain little or no vegetation, provide little wildlife habitat, and pollute streams. Reclamation and afforestation of these sites has the potential to sequester large quantities of carbon in terrestrial ecosystems. Approximately 1.6 million acres of land in the U.S. supports only limited vegetation due to past and present mining operations. Over 1.8 million hectares of land nationally (including 1.1 million hectares in the east) were under active coal mining permits during 2001; of these lands, over 600,000 hectares (including 200,000 hectares in the east) are currently classified as "disturbed". Converting these abandoned lands to productive forests has the potential of sequestering a long range total of over 100 million metric tons of carbon. DOE-NETL's terrestrial sequestration activities are aimed at developing hardwood and conifer forests on eastern U.S. coalfields, not only to sequester carbon but also to support a wood products economy, help control flooding, and provide clean water, wildlife habitat, biodiversity, and recreation (NETL, 2004).

Abandoned and previously reclaimed mine lands in the Appalachian region may provide excellent sites for enhanced terrestrial carbon sequestration through reforestation. Because soils in these areas are essentially devoid of carbon after mining, the planting of forests can dramatically affect carbon uptake of these sites, thus increasing carbon accumulation in soils and forest biomass. For example, DOE-NETL has initiated a reforestation project at several locations within Kentucky. These sites differ with respect to geology and reclamation practices. Various methods are being employed to decrease both physical and chemical limitations on plant growth so that the establishment of high value forest species (hardwood and conifers) is possible. The primary goal is to establish planting sites to demonstrate low compaction surface mine reclamation techniques for carbon sequestration through the growth and harvesting of high value trees (NETL, 2004).

When land is surface-mined, the entire forest, including shrub layer, tree canopy, root stocks, seed pools, animals, and microorganisms is removed. After reforestation reclamation, this complex forest can in time be restored to its original function and structure via forest succession. A combination of grasses, legumes, nurse shrubs and trees, and crop trees are established more or less simultaneously. Each plant type serves a specific reclamation function then yields to another plant type. Pioneer species such as legumes, shrubs, and resilient pine and hardwood species become established first, then eventually yield to the more site-sensitive hardwood crop trees as they close canopy. Reforestation best practices are designed to accelerate forest succession while providing land stabilization and erosion control (Burger, et. al., 2002).

2.5.9.1.1 General Design and Operating Parameters

Rates of carbon sequestration on forest lands depend on the management practices adopted, the species of trees involved, and the geographic area covered. For any given land-use change, sequestration rates will vary considerably depending on the region and vegetation species involved. For example, conversion to loblolly pine in the Southern Plains states leads to rapid uptake of CO_2, peaking at approximately 16 tons CO_2 per acre per year in the second decade of growth, and declining rapidly thereafter, with carbon uptake becoming insignificant after 70 years. In contrast, ponderosa pine plantations in the Mountain states region exhibit a gradually increasing rate of CO_2 sequestration over 70 years, peaking at about 11 tons CO_2 per acre per year, and declining gradually over the succeeding century. Forty to seventy-year uptake rates reported for these trees ranged from 6-7 tons CO_2/acre/year. Thus, the total quantity of carbon sequestered over the lifetime of a plantation may be greater in the case of ponderosa pine, but the sequestration occurs much later with loblolly pine, which is probably attributable to differing growth rates between species. Among various U.S. studies, the range of estimates for overall forest carbon sequestration potential is from 3 to 17 tons CO_2/acre-year (Stavins and Richards, 2005). Various U.S. based terrestrial reforestration sequestration projects have reported long-term uptake rates ranging from 5 – 20 tons CO_2/acre/year, with an average of 10 tons CO_2/acre-year.

Based on the above, for the forestation sequestration model project, long-range average CO_2 offset rates of 8-10 tons CO_2/acre-year are assumed (7.25 to 9.1 MT CO_2/acre-year). The DOE, UtiliTree and PowerTree U.S. projects range from 200 to 1,100 acres each (Kinsman, 2001; PowerTree, 2004). Various international projects involving tree planting or reforestation range from 1,000 acres to 500,000 acres, but with most projects significantly less than 100,000 acres (FAO/ISRIC, 2004). Therefore, the minimum and maximum project sizes for this analysis are based on 500 acres (DOE, UtiliTree/PowerTree project) and 10,000 acres (Southern Company/AEP/large international project) (Summer et al., 2004; Boyd, 2003; Loeffelman et al., 2005).

It is important to understand the magnitude of the hypothetical terrestrial sequestration programs under consideration. The amount of land involved is quite large—approximately 4 million acres for a program achieving 25 million tons of CO_2 sequestration per year and 15 million acres for a program achieving 100 million tons of CO_2 sequestration per year. This would be a large amount for the U.S. to absorb—and so a program of this size would need to be implemented gradually over many years. Additionally, these land requirements far exceed the total abandoned mine lands in the U.S. Therefore, to achieve these carbon sequestration goals, terrestrial sequestration will likely contribute only a small portion of the overall U.S. carbon sequestration program, and would have to be applied beyond mine lands alone.

Since about the 1980's, in several states mined land planted with trees has been designated as "unmanaged forest land", or "non-commercial forest land" in mining permits. Another forest land post-mining land use option is "commercial forest land' or "managed forest". Commercial forest land provides an opportunity to use alternative reclamation practices to achieve a wood production forestry management objective. For commercial forestry (and to maximize carbon sequestration potential), a minimum stocking of 400 trees per acre is required. Similarly, 600-700 trees per acre should be established for good forest stand development by a combination of planting, seeding, and natural invasion. Performance criteria for regulatory required bond release by mining companies have been achieved for forest land. Of particular importance are requirements relative to final surface grading, ground cover, and number of trees per acre. Grading should be minimized to avoid surface soil compaction, with small gullies left un-repaired. Ground cover must be adequate to control erosion and achieve the specified land use success standard (Burger et al., 2002).

A generalized description of the model project parameters is included in Table 2-28. The model includes the sequestration of CO_2 as a result of establishing a forest ecosystem in an area where it is non-existent at the present time. The general design of the project includes several steps:

- Develop objectives and goals for the project;
- Determine what type of project could feasibly meet the stated objectives or goals;
- Determine the size of the site required to fulfill the objectives and goals;
- Determine the type forest (ecosystem and species specific); and
- Determine the life of the project (typically this can range from 40 to 100 years).

2.5.9.1.2 Environmental Process Discharge Streams and Benefits

The model project is expected to contribute only insignificant increases in air or water pollutant emissions, primarily during the initial phases of site preparation and planting. Subsequent years could see the need for maintenance for weed/competition control and application of pesticides if needed. The increase of CO_2 and other emissions from maintenance and equipment use will be insignificant in comparison to the overall net CO_2 sequestration of the planted forest. Other environmental issues associated with any type of land disturbance include sedimentation and erosion issues, especially if located near a stream or ditch, decrease in air quality if working dry land due to dust or other sediments, and any type of oil/fuel leaks of machinery working on site preparation or maintenance. These issues can be avoided if best management practices are used when installing and maintaining the project. The project is only expected to produce negligible amounts of wastes.

The benefits of forestation will improve degraded sites by addressing water quality issues of erosion and sedimentation as the forest becomes established. Forestation projects will also provide additional benefits such as increased biodiversity, restoration of wildlife habitats, enhanced flood control, provide public recreation opportunities, and help support a wood products economy. Therefore, given the insignificance of any environmental concerns, and the broad and diverse suite of associated environmental benefits, forestation sequestration projects will have only positive overall impacts on the environment.

Reclaimed mine soil sites covering a wide range of quality have been constructed, from sites on which trees are unable to survive, to sites on which trees are growing at rates faster than on natural, undisturbed soils; when reclaimed properly, mine soils can produce a harvestable tree stand in 35 years with six times more board-foot volume than that produced on a poor quality site (Torbert et al., 1988). Hardwoods growing on poor sites have virtually no commercial value, while timber value of hardwoods on good sites can be as much or more than that on non-mine sites with product values many times greater than that from a poor site (Burger et al., 2002).

2.5.9.1.3 Site Requirements and Operations

The land design of a forestation/reforestation project can range in size from small tracts of isolated land to very large continuous tracts depending on what is available and what other specific objectives the project may have such as restoring a bottomland hardwood forest, maintaining a sustainable timber reserve, or reclaiming a mining site. The amount of CO_2 sequestered will be directly proportional to the size of the project site, number of trees present, and the species of these trees. Logically, the larger the site the more CO_2 can be sequestered due to the number of trees and potential amount of biomass that each site can support. However, factors such as spacing requirements can affect this ratio. For example a smaller site may be designed with a 10-foot by 10-foot tree spacing while a larger site may be at a 15-foot by 15-foot spacing and therefore, each will support approximately the same number of trees and associated biomass.

Table 2-27 gives estimates of tract size and number of trees on those sites depending on spacing densities and therefore, approximates the amount of biomass per site available to capture CO_2.

Table 2-27. Number of Trees by Tract Size

Land Area of Size (acres)	Spacing of Species - 10' by 10' Spacing	Spacing of Species - 15' by 15' Spacing
	Number of Trees on Site	
10	4,350	1,940
50	21,750	9,700
100	43,500	19,400
500	217,500	97,000
1,000	435,000	194,000
5,000	2,175,000	970,000
10,000	4,350,000	1,940,000
50,000	21,750,000	9,700,000

Determining the type of forest ecosystem desired from a reforestation project must be defined early in the process as this will affect the site selection, species to plant, and site preparation. If the desired community is a plantation, then the site requirements such as soil type and rainfall are known and an appropriate site can be acquired for a single species composition. However, if a more diverse, naturalized forest ecosystem is the goal, then the species selected should approximate a natural community with appropriate species, different community layers, staggered spacing, etc. Again, all of these issues need to be determined when initially designing the site and subsequently developing the planting scheme.

The following conditions are necessary for proper tree growth and survivability on mined lands:

- The final surface layer must be composed of an acceptable rooting medium, placed on the surface to a depth of at least four feet to accommodate deeply rooted trees, and which is less intensively graded to minimize soil compaction.
- During the reclamation process, all highly alkaline or acidic materials with excessive soluble salt levels should be covered with four to six feet of acceptable rooting medium that will support trees.
- Select tree species that provide long-term erosion control, are compatible with one another, and are suited to site-specific conditions.
- Ground cover should include grasses and legume species that are slow growing, pH tolerant, and can be established in a bare mineral spoil; aggressive or invasive species must be avoided. Tree species selection should be based on an approved post-mining land use and site specific characteristics, whether it be a non-commercial (unmanaged) forest land, commercial (managed) forest land, or an area managed for fish and wildlife use (Campbell, 1997).

Two categories of trees are recommended: crop trees, or commercially valuable timber crop species, and nitrogen-fixing wildlife/nurse trees (or shrubs). Crop trees are long-lived species that offer value to landowners as salable forest products. Commonly planted crop trees include pines, poplar, ash, maple, and other hardwood species. On well-constructed mine soils, most native hardwood species grow well, with critical growth and survival factors including spoil type, compaction, slope aspect and position, and competition from ground cover grasses and legumes. Nurse trees are planted to assist the crop trees by enhancing the organic matter and nitrogen status of the soil, and improving soil physical properties. Nurse trees will die or can be cut out after 15 to 20 years when crop trees need additional growing space (Burger et al., 2002).

When selecting a site for a reforestation project, it is very important to realize the costs associated with site acquisition, as the most important factor affecting the cost of forestry-based carbon sequestration in the U.S. is the opportunity cost of land (i.e., the value of the affected land for alternative uses). Relevant opportunity costs include costs for land, conversion, plantation, establishment, and maintenance, as well as competing costs and prices for other land uses (e.g., agricultural).

Average farmland costs across the nation vary significantly, averaging $1360/acre. The low end averages $265/acre in New Mexico spiraling upward to $10,200/acre in Connecticut and Rhode Island (USDA 2004a). One option is leasing land which will defray the costs associated with purchasing land. However, other options to include purchasing the land outright will require some form of legal agreement/easement to assure the protection of the site for the life of project. This is a cost associated with developing the forestation/reforestation project. The greatest cost savings associated with reforestation as compared to creating hayland/pasture is due to reduced need for grading. Planting 600 trees/acre can be accomplished for about $300/acre provided soil compaction has been avoided and a tree-compatible ground cover has been established. Under these conditions, enough trees will surviv to result in a viable forest (Burger et al., 2002). The costs of land, planting of groundcover and trees, and forest management for timber production and/or creation of wildlife habitat will affect the overall potential for implementing forest-based CO_2 sequestration projects in the U.S.

Based on previous reforestation terrestrial sequestration projects, the model project is expected to require 500 acres of land for the pilot scale project, and 10,000 acres of land for the commercial scale project. With an active mining or bond released site, it is assumed that no new access roads will be required; however, for abandoned mine sites, it is estimated that a maximum of 4 to 50 miles of access roads would need to be re-established to support the pilot and commercial scale reforestation projects, respectively.

2.5.9.1.4 Construction Phase Activities

After acquiring the site, the first step is to prepare the site for planting. Preparations can include several tasks which are entirely dependent on existing site conditions. The site may need to be cleared, disked, subsoiled, soil amendments and/or pre-planting herbicides applied, etc. Again, these tasks all depend on the needs and condition of the individual site. Site preparations are estimated to require three crews of four with the appropriate machinery 30 days to prepare the 500 acre pilot scale site, and six crews of four 300 days to prepare the 10,000 acre commercial scale site.

Site preparation may require herbicide treatment, depending on the existing species of ground cover. There are several methods to prepare a mined site by ripping. One method is to deep cross-rip with a single tine using the planting spacing as the guideline. The soil should be ripped a minimum of three feet, more if possible, because the deeper the roots can penetrate the higher the resultant site index (i.e., height of the tallest trees at a given age). Rocks are pulled out from below for maximum fracture. Other methods use multiple tine rippers with no cross ripping, excavators, and smaller ripper configurations.

The next step towards completing the project is planting or seeding the prepared site. Number of seedlings can also vary depending on spacing including the desired visual effect and species as mentioned earlier. A 10-foot by 10-foot spacing would require 435 plants/acre and a 15-foot by 15-foot spacing would require 194 plants/acre. There are several methodologies for planting the seedlings; two of the most common are mechanical or hand planting, both of which should be completed from November to April, prior to the beginning of the respective growing season in the area. Seedlings should be planted as soon as possible in late winter or early spring after the ground has thawed, as the soil is usually wetter, more conducive to root growth, and roots are established before the weather turns warm enough for shoot growth to begin (Burger, 2002). Additional planting may be necessary in later seasons if there is a large percentage of mortality in the plants. It is estimated that a crew of three would take 2 months to plant the 500 acre pilot scale site, and a crew of twelve would take 10 months to plant the 10,000 commercial scale site.

The last steps in reforestation will include several tasks after planting. Following establishment of a forestation project, there are ongoing maintenance activities and costs, including those associated with fertilization, thinning, security, and other MM&V activities necessary to realize expected carbon sequestration results. Activities and costs associated with fire and pest protection, as well as preventing the establishment of noxious and/or invasive plant species, may also be incurred. These tasks may or may not be necessary dependent on weather, site conditions and any other requirements of the project, including post-planting herbicides, pesticides, additional soil amendments, post planting monitoring, and possibly cultivation, depending on plant competition, etc. A final step that may occur 5-10+ years on the horizon includes thinning and/or harvesting if the site requirements are such.

2.5.9.1.5 Utility Requirements

No utility requirements are necessary in this forestation/reforestation model project case.

2.5.9.1.6 Monitoring, Mitigation, and Verification (MM&V)

Monitoring, mitigation, and verification of carbon cycling in forests, wetlands and riparian zones, and agricultural practices provide significant challenges, and most methods are not simple or rapid assessments (Wylynko, 1999). A variety of techniques are available to monitor and verify carbon storage in forests and other terrestrial systems, including field site measurements like biomass surveys (considering research studies, surveys, and inventories), and measurements of soil carbon, or modeling and remote sensing techniques (Ferguson et al., 2003).

Many groups believe that accounting for changes in terrestrial carbon stocks is inherently more difficult than for combustion or other industrial processes. Two significant problems are resolution, the ability to recognize small changes in large numbers, and maintaining the infrastructure needed for regular measurement of change in carbon stocks. Temporal and spatial variability contribute to higher uncertainty in estimates of carbon stocks. Accounting for reforestation project-level activities is different from national-level accounting, because project-level MM&V does not need to be as spatially comprehensive. However, lack of spatially comprehensive accounting of carbon stocks for individual projects may make it more difficult to recognize and compensate for project CO_2 losses (Schlamadinger and Marland, 2000).

Given that, DOE-NETL has Carbon Sequestration Program MM&V goals to develop instrumentation and measurement protocols to accurately monitor, mitigate, and verify carbon storage, and provide for 95 percent of CO_2 uptake in a terrestrial ecosystem to be credited. Above-ground MM&V is specific to terrestrial sequestration and involves quantification of the above-ground carbon stored in the forest vegetation. Traditional field practices provide fairly accurate estimates of above-ground carbon, but those methods are time consuming and labor intensive. In response to that, DOE-NETL is developing aerial and satellite-based technology to study forestation projects, to determine their carbon sequestration potential, and validate software models to predict carbon storage in forests. DOE-NETL is funding the development of Multi-spectral, 3-Dimensional Aerial Digital Imagery (M3DADI) for terrestrial sequestration MM&V. Dual cameras and laser are attached to an airplane to create a three-dimensional image of a forest plot. From correlations with stock inventories and ground measurements, these modeled images are used to estimate the amount of carbon sequestered. The technology is being validated in several large forestation projects by comparing this technology to conventional sampling methods (NETL, 2004).

For this model project case, it is anticipated that conventional field sampling and analytical procedures would be utilized as part of a pilot scale forestation project. Conversely, a much larger commercial scale project would likely utilize DOE-NETL's M3DADI technology.

2.5.9.2 Case B: No-Till Agriculture on Mined Lands

The area of research on carbon sequestration associated with agricultural practices is led by the USDA, and supported by other government agencies and non-governmental organizations (NGOs). However, as part of the Phase II pilot field validation tests, one or more agricultural practice-based projects have been selected and subsequently executed in the field. Additionally, DOE-NETL does have several ongoing research projects investigating methodologies and developing instrumentation for monitoring soil carbon contents. Therefore, this summary case on no-till agriculture is included in the carbon sequestration by mined lands model project, to serve in part as a relative descriptor by which any future DOE-NETL agricultural practice field test projects could be assessed.

Cropland agriculture results in GHG emissions from multiple sources, with the magnitude of emissions determined, in part, by land management practices. Cultivation and management of soils leads to emissions of N_2O, CH_4, and CO_2. However, agricultural soils can also mitigate GHG emissions through the biological uptake of organic carbon in soils via CO_2 removal from the atmosphere (USDA, 2004b).

The size of CO_2 emissions and sinks in soils is related to the amount of organic carbon stored in soils. Changes in soil organic carbon content are related to carbon inputs, e.g., atmospheric CO_2 fixed as carbon in plant tissue through photosynthesis, and soil carbon losses mainly caused by decomposition of soil organic matter causing CO_2 emissions. Land use and management affect the net balance of CO_2 uptake and loss in soils through modifying carbon inputs and rates of decomposition of organic matter. Changes in agricultural practices such as tillage can modify both organic matter inputs and decomposition, thus resulting in a net flux of CO_2 to or from soils (Houghton et al., 1997).

After mining operations, or decades of previous cultivation, most soils have likely stabilized their soil carbon content at lower carbon levels. Changes in land use or management practices that result in increased organic inputs or decreased oxidation of organic matter, e.g., reduction or elimination of tillage, will result in a net accumulation of soil organic carbon until a new equilibrium is achieved (USDA, 2004b).

On an area basis, the amount of carbon stored in agricultural soils typically exceeds that stored in vegetation in most ecosystems, including forests. However, in the U.S. the net annual forest carbon stock change resulting in increased carbon sequestration far exceeds the total GHG emissions associated with cropland agriculture (by a factor of 4 to 5). Additionally, the total U.S. carbon sequestered via cropland management and the Conservation Reserve Program is on the order of only 20 $MMTCO_2$/year (USDA, 2004b). Given the above, and that forestation CO_2 sequestration rates on the order of 10 tons CO_2/acre-year are much higher than that for no-till agricultural practices, this no-till agriculture case will have much less of a carbon sequestration contribution than a forestation project of equal size. Therefore, the forestation case serves as the basis of the carbon sequestration by mined lands model project.

In the MM&V area, soil MM&V involves tracking carbon uptake and storage in the first several feet of topsoil. DOE-NETL is developing two instrumentation approaches to monitoring soil carbon: Laser Induced Breakdown Spectroscopy (LIBS), and Inelastic Neutron Scattering (INS) soil carbon analyzer. The LIBS system offers the ability to distinguish between organic and inorganic carbon, and rapid field-deployable, portable, cost effective method for soil carbon determination. The INS system offers a non-invasive, non-destructive means of continuously monitoring the soil carbon inventory over both specific plots, and large areas. Either one or both of these MM&V technologies could support soil carbon monitoring in a no-till agriculture field test.

Table 2-28. Forestation/ Reforestation on Mined Lands Model Project Data Sheet

Parameter	Activity Description/ Basis	Low	High
Site Acquisition (acres)	Based on small DOE or UtiliTree demonstration project at low end, and large commercial utility or international project at high end.	500	10,000
Number of Trees (approx.)	Based on tight 10' by 10' spacing to maximize sequestration rates.	200,000	4,400,000
CO_2 Sequestration Rate (tons CO_2/acre-yr)	Based on several DOE/UtilTree demonstration project estimates, and mid-range of publicly reported estimates in the U.S.	8	10
CO_2 Sequestration, (tons/yr)		4,000	100,000
CO_2 Sequestration, (MT/yr)		3,630	90,720
CO_2 Sequestration Total (million tons)	Assume 70-year life, median of 40-100 year basis of publicly reported estimates	0.28	7.0
Site /Land Preparation: Clearing, Disking, Ripping, Pre-planting Weed Control, Fertilization (Months)	Required to prepare soil; sometimes necessary in site preparation due to severe compaction – equipment needed include tractor and subsoiler plow, herbicide and tractor, sprayer, fertilizer and tractor, fertilizer spreader equipment, labor.	1	10
Hand Planting (Months)	Timing Nov. to April.	2	N.A.
Mechanical Planting (Months)	Timing Nov. to April.	N.A.	10

2.5.10 Co-Sequestration Model Project

This model project was developed to evaluate the environmental-related considerations associated with the upstream processing steps for co-sequestration of CO_2 and H_2S. Such a co-sequestration approach would involve either EOR operations, or other geologic CO_2 sequestration (and H_2S disposal) in saline formations; therefore, a CO_2/H_2S co-sequestration case is included in each of those two model projects. This model project focuses on the two upstream gas processing/capture options for providing the co-sequestration gas stream. In the first option, CO_2 and H_2S are recovered as a byproduct from integrated gasification with combined cycle power generation technology (IGCC). In the second option, CO_2 and H_2S are recovered from sour associated gas production operations in the oil and gas industry.

The key aspects of the model project related to environmental considerations are described in the following sections:

- General design and operating parameters of the project, with primary focus on the gas-water shift and acid gas removal and recovery operations for the IGCC case, and the acid gas removal and sulfur recovery for the sour gas case;
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.10.1 Case A: IGCC with CO_2/H_2S Capture

The IGCC generation process integrates a gasification system with a conventional combustion turbine combined cycle power generation unit. The gasification process converts coal, or other solid or liquid feedstocks, into a hydrogen-rich gaseous fuel stream (referred to as synthesis gas or syngas). The syngas is then used to power a conventional combustion turbine combined cycle power plant with significantly lower SO_x, PM, mercury, and NO_x emissions. For the purposes of this model project case, the carbon in the raw syngas stream (in the form of CO) is converted to CO_2, separated, and recovered, together with H_2S.

Both the gasification process and the combined cycle generation technology are widely accepted as mature technologies. However, the integration of IGCC technologies is relatively new, with capital costs about 20-25 percent higher than conventional pulverized coal (PC) power systems. The integration of gasification with combined cycle technology is currently in commercial operation in few power plants[1], with Polk River, Florida and Wabash, Indiana in operation in the U.S.

In addition, the downstream gasification process steps to generate, separate, and recover CO_2 are commercially demonstrated. The Great Plains Synfuels Plant process recovers acid gas (CO_2 and H_2S) for resale and pipeline transport to the Weyburn field in Alberta, Canada for EOR operations. Therefore, all process operations associated with the model plant are based on commercially demonstrated technology. Advanced technologies are being developed for several of the process operations to enhance the system overall efficiencies, which are identified in the following process description section.

[1] There are 12 major IGCC plants in operation internationally, with 5 of those designed with the primary intent of commercial-scale electricity production. The remaining applications are in refining and petrochemical service, with electricity production as a secondary process.

2.5.10.1.1 General Design and Operating Parameters

Model Plant Process Description. The process flow for the IGCC with CO_2 recovery model project is illustrated in Figure 2-13. The primary unit operations in the plant include:

- Coal handling and feed slurry preparation;
- Air separation and coal gasification process;
- Water-gas shift and syngas humidification;
- CO_2 and H_2S separation and compression; and
- Combined cycle power generation.

As shown in Figure 2-13, coal feedstock is crushed, pulverized, and mixed with water to form a slurry for injection. The coal slurry is heated and fed to the gasification injection system. Oxygen of 95% purity is separated from air in a cryogenic air separation unit, which includes multi-stage compression, thermal swing absorption, and cryogenic distillation to separate the purified oxygen feed.[2]

The gasification technology assumed for this model project case is an entrained-flow reactor design.[3] Gasification occurs in an oxygen-limited reducing environment, where partial oxidation creates heat and a series of chemical reactions produce syngas. In the primary gasification zone, the heated coal slurry, oxygen, and recycled char from the candle filter are injected. The primary gasification zone operates above the ash fusion temperature (over 1200 deg. C), to allow the molten slag to flow from the reactor for removal, quenching and disposal (or resale for construction building products, etc.). The gaseous stream formed from the exothermic, partial oxidation process in the primary zone passes to the secondary zone. Coal slurry and raw fuel gas recycle are injected in the secondary zone, where the gasification reactions are endothermic, with exit gas temperatures of around 1040 deg. C. Waste heat is recovered from the raw gas stream to generate high-pressure process steam. Char and fly ash produced in the gasifier is entrained in the raw gas stream and removed in a particulate candle filter downstream of the waste heat recovery.

The cooled raw gas is mixed with steam and passed through high- and low-temperature water-gas shift reactors used to oxidize the CO in the raw fuel gas to CO_2. The fuel gas is cooled and routed to an acid gas removal (AGR) unit using Selexol[4] as the solvent. The AGR unit is a counter-current gas absorber unit that contacts the fuel gas stream with Selexol to remove CO_2 and H_2S from the fuel gas. The sweetened fuel gas stream exiting the top of the AGR separator is saturated with water (i.e., humidified), and then combusted in the gas turbine for combined cycle power generation. The fuel gas humidification process is designed to lower burner temperatures during combustion of the fuel gas in the combustion turbine, resulting in reduced NO_X emissions from power generation.

The rich Selexol from the AGR unit is regenerated by stripping the CO_2 and H_2S from the rich Selexol solvent in a regeneration process. The lean Selexol from the bottom of the regenerator is recycled back to the AGR separation unit, while the regenerator overhead stream, concentrated CO_2 and H_2S, is condensed to remove water, then compressed in multi-stage, intercooled compressors with glycol (or molecular sieve) dehydration to supercritical conditions. This concentrated H_2S-laden CO_2 stream is metered and transported via pipeline for EOR operations.

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[2] Advanced air separation technologies are under development, including membrane separation with significantly reduced energy intensity. For the model project, conventional cryogenic air separation technology is assumed based on commercial availability and demonstration.
[3] Commercially available gasification technologies include moving-bed reactors, fluidized-bed reactors, and entrained-flow reactors. Nearly all commercial IGCC systems in operation or under construction are based on entrained-flow gasifiers (commercial technology vendors include ChevronTexaco, ConocoPhillips, Shell, Prenflo, and Noell).
[4] Selexol is a physical absorption process favored at high pressure operation.

Model Project Design and Operating Parameters. Two model project sizes were considered for evaluation of the environmental considerations, based on combined cycle generation capacity as the critical design factor. The lower model plant capacity limit is consistent with the EOR model project size limitations as a pilot scale operation. For this scenario, the IGCC operation would be assumed to be an existing operation, such as the Wabash Power Station in Indiana, with a slipstream of the amine regenerator overhead supplying the CO_2 stream for an EOR (or saline formation) pilot project. For this low capacity scenario, the overall impacts on the IGCC facility operations and emissions would be minimal. In addition, this case example would have similar or lower impacts than the low capacity scenario for the post-combustion capture model; therefore, detailed calculations for the low capacity scenario are not included here. Also, IGCC slipstream-based CO_2/H_2S co-sequestration pilot projects are not anticipated to be a part of the Phase II field validation tests.

The high capacity model plant is based on two Siemens V94.2 gas turbine units in combined cycle configuration for a net output of 520 MW. This plant size is representative of the largest commercial installations of IGCC technology, although the existing plants use refinery residue instead of coal as feedstock. The gasification technology assumed is ChevronTexaco oxygen blown, entrained flow design. Such a large scale project could be performed at an existing gasification site, or be based on a new, greenfield plant.

Table 2-31 includes the model project design and operating parameters for the high capacity plant. Plant efficiencies of 37 percent are lower than IGCC technology without CO_2 capture and compression facilities (see following section for CO_2 recovery auxiliary power requirements). The model plant performance profiles are scaled based on design specifications from the EPRI study (EPRI, 2000), or other sources as noted, where data for actual applications are not available.

2.5.10.1.2 Utility Requirements

Utility requirements included in Table 2-31 are for the CO_2/H_2S capture and recovery steps of the IGCC plant. The plant-wide auxiliary power requirements for IGCC with CO_2 recovery are summarized as a percentage of the total auxiliary load in Table 2-29. As shown, the cryogenic air separation unit accounts for a large fraction (around 29 percent) of the parasitic load of an IGCC facility. The incremental electricity requirements for the CO_2 capture process steps are minimal, as the compression operations are already captured under the CO_2 transport model plant. These differences are captured in Table 2-31, based on published data for IGCC with and without CO_2 capture.

Table 2-29. Auxiliary Power Requirements for IGCC.

Process Unit Operation	Auxiliary Load (% total auxiliary load)
Air separation plant	29
CO_2 separation in AGR Selexol plant	7
CO_2 compression	20
Oxygen boost compressor	12
High pressure boiler feed pump	3
Balance of plant	29
Total auxiliary power requirements as % of gross generation	18 (% of gross power)

Source: EPRI, 2000.

Water make-up rates shown in Table 2-31 are for the entire IGCC plant, as well as for the utility requirements for the CO_2 separation operations. For the CO_2 operations, cooling water is used primarily to wash the syngas stream exiting the absorber, with make-up water to account for system losses. Make-up water requirements for the CO_2 operations range are 535 gpm for the high capacity model plant.

Solvent recirculation rates for the AGR unit were assumed as a basis to quantify the total solvent make-up rates. Data from published studies were used as the basis for the estimates. Total solvent make-up rates are estimated at 7-14 gpm, or over 20,000 gallons per day for the high capacity model plant. Solvent would be delivered to site via railcar or tank truck.

During the absorption and regeneration processes, entrained solids and chemicals accumulate in the amine solution impairing the treatment efficiency and contributing to foaming and tray clogging. Chemical additives are injected in the recirculated amine solution, including corrosion inhibitors and foam breakers. Soda ash (Na_2CO_3) is used to aid in the precipitation of salts in the amine regenerator. A slipstream of the amine solution is filtered through mechanical filters and activated carbon filters to maintain the amine solution quality.

Hydrated lime is used in the wastewater neutralization process to neutralize the acidic wastewater.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be needed. The fuel oil used for IGCC start-up and a small auxiliary boiler will be stored in a 200,000 gallon storage tank.

2.5.10.1.3 Environmental Process Discharge Streams

Air Pollutant Emissions. The proposed model project would not result in increases in pollutant air emissions. The IGCC model project will result in decreased overall air pollutant emissions as compared to traditional pulverized coal power generation. IGCC power plants achieve air emissions control during the syngas clean-up process, prior to combustion in the combined cycle plant. Compared to post-combustion emissions control, IGCC offers more cost effective control in treating concentrated, higher pressure and lower mass flow streams as compared to conventional flue gas treatment technologies.

Table 2-30 provides the projected air emissions levels from IGCC with CO_2 recovery technology, compared to NSPS levels for coal power generation. These emissions represent plant-wide emissions, not just the process steps associated with CO_2 recovery. Incremental air pollutant emissions from the CO_2 separation and capture process are negligible, with the exception of CO_2 emissions. CO_2 emissions from the IGCC with CO_2 recovery model plant would be substantively lower than a conventional IGCC without CO_2 capture. Further, emissions of SO_x would actually represent a net decrease in overall sulfur emissions from the avoidance of downstream sulfur removal operations, although overall emissions of SO_x are very low.

Table 2-30. Plant-wide Environmental Performance of IGCC with CO_2 Capture Technology

Air Pollutant	Projected Emissions Levels for IGCC		Coal Power Plant NSPS Limits Lb/MMBtu (HHV)
	Lb/MWh	Lb/MMBtu (HHV)	
SO_X	0.11a – 0.7 b	0.013 a – 0.08 b	1.20
NO_X	0.25 a – 0.77 b	0.028 a – 0.08 b	0.15
CO	0.32 c	0.036 c	
PM	0.100 b	0.011 b	0.030
VOC	0.01 c	0.001 c	
CO_2	162d	21.4 d	

[a] Based on NETL/EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, Dec. 2002.

[b] Based on NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002.

[c] Based on ChevronTexaco, May 6, 2003.

[d] Based on EPRI, Dec. 2000.

For the entire IGCC plant, SO_x emissions are dictated by: a) the sulfur content of the coal feedstock, and b) the H_2S removal efficiency in the acid gas removal process for syngas clean-up and CO_2 recovery. High temperature gasification of coal produces H_2S and small amounts of carbonyl sulfide (COS). The acid gas removal process removes 95 to 99+ percent of the sulfur in the raw syngas. The remaining sulfur in the syngas stream is oxidized to SO_2 in the combustion turbine.

Likewise, CO and CO_2 emissions are minimized by the post-gasifier water-gas shift reaction oxidizing CO to CO_2, and the subsequent acid gas removal process to remove CO_2 from the syngas stream. Levels of CO_2 emissions from the power plant will be based on:

a) the water-gas shift reaction conversion efficiency, and

b) the CO_2 removal efficiency in the acid gas removal unit.

NO_X emissions are inherently low due to very low levels of fuel bound nitrogen in syngas, as well as the lowered turbine flame temperatures achievable with combustion of humidified syngas, coupled with steam injection, to limit thermal NO_f formation. Particulate matter is reduced through the separation of the char and ash entrained in the gasification process and recovery of molten slag from the gasification reactor.

Water and Solid Waste. IGCC facilities use water for the plant's steam cycle as boiler feedwater, cooling water and for other processes, such as syngas humidification and acid gas removal aqueous solvent make-up. Most process water in an IGCC plant is recycled to the plant, which minimizes consumption and discharge.

The acidic wastewater is neutralized with hydrated lime, oxidized by air injection, and flocculated to remove solids. The sludge would be dewatered and disposed of off-site.

The largest quantity of solid waste from an IGCC facility is slag, which is a non-leachable material that can be sold as a byproduct for applications such as asphalt paving aggregate or construction backfill.

2.5.10.1.4 Site Requirements and Operations

Coal is delivered to the site by unit trains of 100-ton railcars. Each unit train consists of 50-100 railcars, which are unloaded into 2-3 receiving hoppers. The coal is then conveyed to a reclaim pile. Coal from the reclaim pile is fed to a surge bin located in the crusher tower. Crushed coal is conveyed to 2-4 storage silos. The coal from the storage silo is fed to a rod-mill to pulverize the coal and mixed with water to form a slurry, heated, and stored in an agitated slurry tank.

Gasifier technology is assumed to be entrained-flow, oxygen blown technology with a maximum coal throughput per gasifier of 1,250 tpd (dry, with heating value of coal of 11,700 Btu/lb, HHV). The high capacity model plant (520 MW, net) would require up to 6 gasification trains.

The raw syngas is treated in 2-4 water-gas shift trains of high and low temperature shift reactors, steam generators, and fuel gas expanders.

The CO_2 recovery plant would include 2-4 absorber and regeneraton trains. Each absorber train would include 3 absorber towers, for a total of 6-12 absorber towers with approximate dimensions of 15 ft. diameter and 80 ft. height. Likewise, each regeneration train would include 2-4 stripper towers, with approximate dimensions of 15 ft. diameter by 75 ft.

The CO_2 and H_2S stream recovered from the amine regeneration strippers is compressed in 1-2 multiple-stage, intercooled compressors to supercritical conditions. During compression, the CO_2 stream is dehydrated in a triethylene glycol (TEG) unit. The temperature and water content of the CO_2/H_2S stream are important design parameters to avoid hydrate formation and corrosion. Methanol may be injected to avoid hydrate formation.

Fuel oil, amine solvent, soda ash, and hydrated lime are delivered by truck. Truck roadways and unloading stations must be provided. Storage hoppers for soda ash and hydrated lime are required, as well as storage tanks for fuel oil and amine solvent. For the amine solvent, from 10,000 to over 20,000 gallons per day will be required. Assuming delivery in 17,000 gallon tank trucks, daily deliveries would be required or weekly in railcars.

Liquid and solid wastes that require disposal from the site include reclaimer sludge, spent carbon from the amine filter beds, and slag disposal or resale. Spent carbon is trucked each week to a landfill for disposal. Slag is trucked to a near-by construction site or industrial user.

Based on the equipment required for the acid gas recovery operations of the IGCC plant, the model project is expected to require about 30 acres of land for the commercial scale project. The IGCC plant access roads are assumed to be adequate for the acid gas recovery operations. To maintain operations of the commercial scale facility, about 12 full-time equivalent skilled personnel would be required to cover three operating shifts per day.

2.5.10.1.5 Construction Phase Activities

To prepare for construction activities, the site would be cleared of ground cover and graded. Access roads and erosion control would be required during the construction phase of the project. Construction temporary facilities would include construction road and parking area construction and maintenance, installation of construction power, installation of construction water supply and general sanitary facilities, and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items. For the commercial scale facility, two crew of six equipped with appropriate machinery would require approximately 20 days to prepare the site.

Additional construction activities would include building foundations for the major equipment and buildings, field erection of equipment, piping, instrumentation and control systems, and utility tie-ins (water, steam, electricity). These construction activities would require heavy machinery and a crew of around 400 personnel working for approximately 1.5 years.

Table 2-31. IGCC with CO_2 Recovery Model Project Data Sheet

Parameter	Description/Basis	Commercial Deployment Level
Description of Model Plant	Model plant is an integrated gasification process to produce syngas fuel from coal, with a combined cycle gas turbine plant for power generation. The syngas clean-up process operations include oxidation of CO to CO_2 in a gas water shift reaction, followed by acid gas removal process for separation and concentration of CO_2 and H_2S for compression, and potential resale for EOR operations.	
Plant Characteristics		
Net Capacity, MW	Based on expected size range. Net capacity based on gross generation less the parasitic load requirements of the plant.	520
Gross power, MW	Based on auxiliary power requirements estimated at 18% of gross generation.	637
Capacity Factor, %	Capacity factor range represents a low and high range for IGCC technology.	65 - 85
Syngas production rate, MMBtu/hr (HHV)	Based on heat rate of 9,300 Btu/kWh, HHV	4,836
Processes:	Coal is pulverized and fed as water slurry to gasification reactor, where it is entrained in 95% pure oxygen stream. The oxygen is separated from air in cryogenic process. Raw syngas stream from the gasifier is water-gas shift reacted to form CO_2. The CO_2 is removed, together with H_2S in an acid gas removal chemical absorption process. The CO_2/H_2S is separated from the rich solvent and is compressed and dehydrated for transport via pipeline.	
Major Equipment associated with CO_2 stream:	Gasifier, syngas cooler, candle filter, flare stack, water-gas shift reactors, waste heat recovery steam generators, raw gas coolers, absorber tower, amine solvent storage tanks, rich/lean heat exchanger, amine solvent regenerator/stripper, reboiler, condenser, pumps, blower, multi-stage intercooled compressor, glycol dehydrator	
Operating Utilities	Steam, electricity, cooling water, boiler feed water, chemicals makeup	
Plant Feed Rates		
Coal Feed Rate, lb/hr	Coal feedstock feed rate on dry basis, assuming heating value of coal is 11,700 Btu/lb, HHV and plant heat rate is 9,300 Btu/kWh, HHV	413,000

Parameter	Description/Basis	Commercial Deployment Level	
Water make-up, lb/hr	Water make-up for process, boiler feed, etc.	858,000	
Oxygen, lb/hr	Feed rate of 95% pure oxygen from the Air Separation Unit to the gasifier	338,000	
Recovered CO_2 Stream			
CO_2 recovered, lb/hr	CO_2 stream flow rate assuming 90% overall CO_2 capture.	764,000	
CO_2 recovered, MT/day	CO_2 stream flow rate assuming 90% overall CO_2 capture.	8,320	
CO_2 recovered, MT/Year		3,035,760	
H_2S recovered, lb/hr	H_2S mass balance assumes that all sulfur in the coal is recovered in the acid gas removal process (over 99 % efficient). H_2S concentration is based on high sulfur coal with sulfur content of 3 percent.	12,400	
H_2S concentration, wt %	Calculated based on mass rates of CO_2 and H_2S recovered.	2	
H_2S recovered, MT/year		49,275	
Utility and Chemical Requirements			
Steam (MMBtu/hr)	Steam requirements (e.g., amine regeneration reboiler) based on mid-range of 4.0 MMBtu/MT CO_2 recovered from published values (Chakravarti et al, 2001; Chinn et al, 2004; Morimoto, et al).	1,390	
Electricity (kW)	Based on difference between auxiliary electricity requirements for IGCC with CO_2 recovery (adjusted to exclude CO_2 compression) and IGCC without CO2 recovery (EPRI, Dec. 2000)	16,200	
Water make-up for CO_2 plant, gpm	For the CO_2 recovery operations, water make-up is based on 180 gpm required for 2,800 MT per day recovered CO_2.	535	
Solvent recirculation rate, gpm	Based on recirculation rate of 2.18 gal. MEA solution/lb CO_2 removed (Chinn et al, 2004)	27,760	
Solvent make-up, gpm	Based on 0.05% loss (Chinn et al, 2004)	14	
Soda Ash, lb/hr	Based on 168 kg/hr for a 4800 gpm solvent recirculation rate (Chinn et al, 2004)	2,140	
Air Emissions		**CO_2 capture only**	**Plant-wide**
CO_2, lb/hr	Mass rate based on 90 percent capture efficiency.	(787,260) decrease[5]	84,885 (10% not captured)[6]
SO_x, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Net decrease[7]	57-364
NO_X, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	130-400
CO, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	166
PM, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	52
VOC, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	5
Wastes Generated			
Reclaimer Sludge, lb/hr	Based on 5000 MT/yr sludge for a 5,200 MT per day recovered CO_2 plant (Simmonds et al)	2,010	
Spent carbon, lb/hr	Based on 114 kg/day for 4800 gpm solvent circulation rate (Chinn et al, 2004)	60	

[5] Overall CO_2 emissions would represent net decrease over IGCC without CO_2 capture. Difference in emissions (i.e., net emissions decrease) is based on EPRI, Dec. 2000.
[6] Assumes IGCC with 90 percent CO_2 capture.
[7] Overall sulfur compound emissions would decrease due to the avoidance of downstream sulfur recovery operations. Emissions for both IGCC with CO_2 capture and without CO_2 capture are reported to be negligible, per EPRI, Dec. 2000.

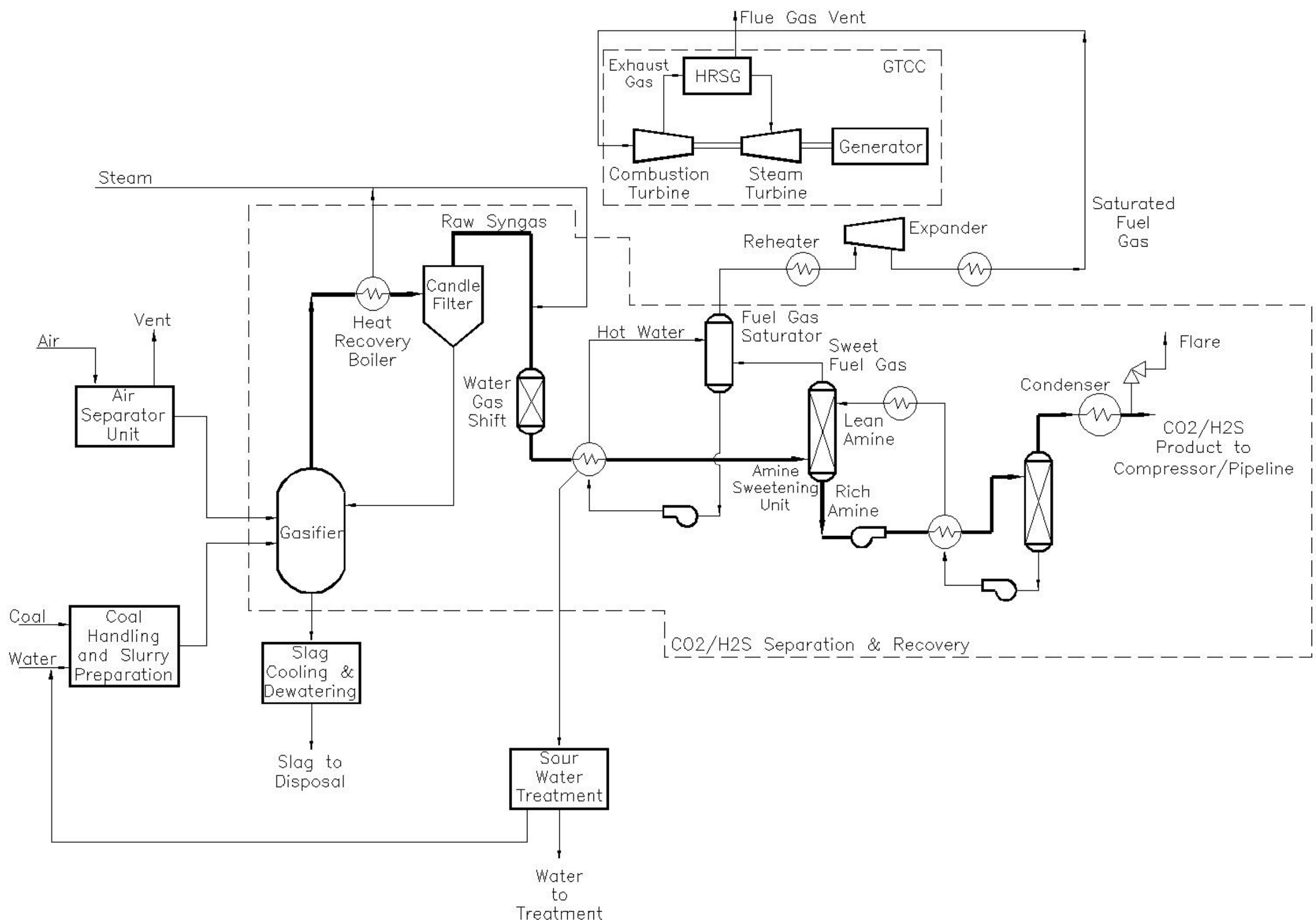

Figure 2-13. Schematic Diagram of IGCC with CO_2/H_2S Capture

2.5.10.2 Case B -- Sour Associated Gas Recovery and Re-Injection for Enhanced Oil Recovery (or Saline Formation CO_2 Sequestration/H_2S Disposal)

This model project case was developed to evaluate the environmental-related considerations associated with the separation, recovery, and re-injection of CO_2 and hydrogen sulfide H_2S in sour oil and gas fields. The model plant is based on capture of the sour associated gas during oil production, separation of the H_2S and CO_2 in a conventional acid gas removal process, and re-injection of the CO_2, with H_2S, for EOR operations. This process is similar to conventional sour gas treatment, except that the sulfur would typically be separated from the CO_2 and further processed as a byproduct stream, whereas the CO_2 would conventionally be vented to the atmosphere after removal from the natural gas stream. In the acid gas re-injection model plant case, the acid gases are re-injected into a suitable underground formation, thus eliminating the CO_2 emissions and the sulfur recovery operations.

In Western Canada, acid gas re-injection technology is operational in over 30 projects. The H_2S composition of the acid gas stream varies widely in these projects, ranging from: 2 percent H_2S in 95 percent CO_2 to 83 percent H_2S in 14 percent CO_2 (molar basis). Wellhead injection pressure varies between 3,750 to 19,000 kPa. Injection rates vary between 2,000 and 900,000 m^3/day for these projects in Canada. Acid gas re-injection is only recommended for sour gas formations where existing production equipment is designed to handle the corrosivity and safety concerns associated with H_2S in the gas. The long-term effects of acid gas re-injection on formation pressure, acid gas concentration build-up, permanence of CO_2 sequestration, and impacts on enhanced oil recovery are being researched.

2.5.10.2.1 General Design and Operating Parameters

Model Plant Process Description. The process flow for the associated sour gas recovery and re-injection model project case is illustrated in Table 2-14. The unit operations of focus for the model plant are those associated with the acid gas stream in the plant, including:

- 3-phase separation of gas, oil, and water;
- Amine acid gas removal; and
- Amine solvent regeneration and acid gas capture (Figure 2-14).

As shown in Table 2-14, produced fluids are transferred from the oil production wells to a centralized production facility using multi-phase pumps. The fluids may pass through a 3-stage lateral separator to meter the fractions of oil, water, and gas fractions, and metering stations are equipped with flares to provide safe release of scheduled and unexpected releases of gas or oil.

The produced fluids are separated into gas, oil and water fractions in a 3-phase separator. Oil may be treated in a heater-treater to flash off any volatile compounds in solution, with the flash gas recovered and added to the gas fraction from the separation process. The oil is desalinated and stabilized prior to transferring to stock tanks.

After the separation of any liquids, the produced sour gas stream is routed to an acid gas removal (AGR) unit using an amine or amine derivative as the solvent. The AGR unit is a counter-current gas absorber unit that contacts the sour gas stream with solvent to remove CO_2 and H_2S from the natural gas. The sweetened gas stream exiting the top of the AGR separator passes through an outlet separator to remove condensed water. The sweet gas may be further processed to separate propane and butane, depending on the gas composition, and the natural gas product is compressed and metered for sale.

The rich amine from the AGR absorber may be fed to an amine flash tank to release the absorbed volatile hydrocarbons. The flash gas is typically combusted in the amine regenerator reboiler or recycled back to the inlet of the amine absorber. Not all sweetening units are equipped with a flash tank. After the flash tank, the rich amine stream is filtered to remove solids and other contaminants. The rich amine stream is then passed through a heat exchanger for preheating before being fed to the top of the amine regenerator. In the regenerator, the amine solution is regenerated by stripping the CO_2 and H_2S from the rich solvent. The lean amine from the bottom of the regenerator is recycled back to the AGR separation unit, while the regenerator overhead stream, concentrated CO_2 and H_2S, is condensed to remove water, then compressed in multi-stage, intercooled compressors and dehydrated to supercritical conditions. This concentrated, H_2S-laden CO_2 stream is metered and transported via pipeline to the injection wells. The compression and pipeline operations are considered part of the model plant boundaries for the CO_2 transport model.

Model Project Design and Operating Parameters. Two model project sizes were selected for evaluation of the environmental considerations. Table 2-32 includes the model project design and operating parameters for the low and high capacity plants, respectively.

The recovered acid gas composition for the low capacity case represents the low range of H_2S concentration in recovered CO_2, based on the existing Canadian projects. The low capacity case is based on 2 wt% H_2S in 98 percent CO_2 at an injection rate compatible with the pilot EOR model project. This low capacity case would represent a slipstream from the regenerator overhead of an existing sour gas processing operation. The incremental requirements for capture of the CO_2/H_2S stream would entail additional piping, valves, instrumentation, and control system configuration at the model plant. The equipment required for compression and dehydration of the slipstream is assumed to be included as part of the CO_2 transport model plant.

For the case of the low capacity model plant, the existing sour gas production facility assumes that sour gas is separated from the hydrocarbon gas stream in a conventional amine AGR unit. The H_2S recovered in the amine regeneration cycle for the existing operations would be flared, incinerated, or sent to a sulfur recovery process. The CO_2 from the existing facility would be vented to the atmosphere. Therefore, the recovery of the slipstream from the amine regenerator overhead for the CO_2/H_2S capture model project would represent an overall savings, albeit small, in energy requirements and subsequent emissions from the existing project scenario.

Both CO_2 and H_2S form hydrates at temperatures up to 10 deg. C for CO_2 and more than 30 deg. C for H_2S, thus operation at temperatures above hydrate formation is a key design parameter. Methanol is often injected to prevent hydrate formation. Therefore, it is anticipated that a methanol chemical injection pump and storage facilities would also be an incremental requirement of the process operations for capturing the acid gas stream.

The high capacity case represents a reasonably high level of H_2S in CO_2 that would be considered appropriate for EOR injection purposes, as opposed to disposal. For model plant design purposes, the design is based on the average inlet H_2S and CO_2 concentrations for diethanolamine (DEA) AGR processes in gas plant duty in the U.S. (GRI, 1991). For DEA AGR processing at gas plants, the H_2S and CO_2 concentrations in the treated gas stream are 1.7 and 4.1 mole percent, respectively, which relates to a concentrated CO_2 stream downstream of the amine regenerator containing 25 percent by weight H_2S.

As in the low capacity model plant case, the existing facility is assumed to be a gas production/processing site that previously recovered sulfur in a sulfur recovery operation and vented CO_2 to the atmosphere.[8] For converting the facility to capture and recover CO_2 and H_2S for reinjection, the only process changes required would be additional piping, valves, instrumentation, and control system configuration for regenerator overhead gas rerouting, addition of a methanol chemical injection pump and injection point for hydrate formation inhibiting, and reduction in or shut down of the existing sulfur recovery operations. Therefore, the recovery of the stream from the amine regenerator overhead for the CO_2/H_2S capture model project would represent an overall savings in energy requirements and subsequent emissions from the existing project scenario.

2.5.10.3 Utility Requirements

Utility requirements included in Table 2-32 are for the CO_2 recovery steps of the sour gas production operations. For the separation process, electricity is required to operate the solvent pumps, coolers, and instrumentation. However, the CO_2/H_2S separation process is considered existing equipment in place for conventional sour gas production. Only in the case of additional capacity in the model plant scenario is there an increase in electricity consumption for CO_2/H_2S separation.

It is likely that electricity consumption for the CO_2/H_2S capture model project would represent an overall net decrease over existing facility operations. This decrease in electricity usage is due to the avoidance of downstream sulfur recovery operations, such as Claus plant treatment and incineration. It should be noted that the energy requirements for CO_2/H_2S compression are not included in the estimates provided in Table 2-32, as they are included in the separate CO_2 transport model project.

Steam is also required for CO_2/H_2S separation operations, but the incremental steam requirement for the model plant is not expected to increase over the existing facility operations. Likewise, water make-up rates are not anticipated to increase over the existing facility operations. Even solvent recirculation rates

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[8] For the high capacity model plant, even in an unlikely scenario where sour gas production operations are considered new plant, the design of the system to handle H_2S would require the installation of an amine AGR process for the oil/gas production baseline operations, even without recovery of the CO_2/H_2S stream for EOR. Therefore, even for a greenfield site application, the acid gas stream recovery for EOR would represent minimal incremental plant modifications.

and solvent loss is not expected to show an incremental increase over the existing operations at the facility.

The only additional consideration for the model plant scenario is the injection of methanol into the recovered CO_2/H_2S stream to prevent hydrate formation during the downstream compression, transport, and injection operations.

2.5.10.4 Environmental Process Discharge Streams

For the CO_2/H_2S capture model plant, the basis of the evaluation is comparison to existing operations in a typical sour gas production or processing facility. As such, the environmental aspects of the model plant project activities would include avoidance of the energy requirements and emissions associated with the partial bypass and/or shutdown of the sulfur recovery operations. The most significant environmental aspect of CO_2/H_2S capture is the avoidance of previously vented CO_2 emissions from the gas production or processing operations. The model project will not result in increases in pollutant air emissions.

Note that the CO_2 stream compression operations are considered part of the model plant boundaries for the CO_2 transport model. Therefore, any environmental considerations, such as combustion emissions associated with gas-driven compression, would be considered in the CO_2 transport model plant and not included here.

2.5.10.5 Site Requirements and Operations

The CO_2 recovery process would require construction of additional piping, instrumentation, and controls. A methanol chemical injection pump is also required in pipe layout to inject methanol into the recovered acid gas stream for hydrate formation inhibiting. As such, only minor equipment, with no major equipment required, is anticipated for the plant modifications needed to integrate the acid gas capture design. Compression and dehydration operations are included in the adjacent CO_2 transport model plant.

Based on the equipment recovered for the acid gas recovery operations at the oil and gas production facility, the model project is expected to require about 1-15 acres of land. No additional access roads are required. To maintain operations of the facility, 3-6 full time skilled personnel would be required.

2.5.10.6 Construction Phase Activities

To prepare for construction activities, the site would be cleared of ground cover and graded. Access roads may be required during the construction phase of the project. General and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items would be included.

Construction activities would include field erection of piping, instrumentation and control systems. For the pilot and commercial scale facilities, one or two crews of three would take 5-10 days, respectively, to prepare the site. Construction activities would require 50-200 personnel 6-12 months to complete construction.

Table 2-32. Sour Associated Gas Recovery and Reinjection Model Project Data Sheet

Parameter	Description/Basis	Low	High
Description of Model Plant	Model plant is a sour oil and gas production operation, with removal and recovery of the CO_2 and H_2S in the gas stream for re-injection operations.		
Plant Characteristics			
CO_2/H_2S recovery capacity, MMscfd	Based on expected size range. For a low capacity plant, recovery of a slipstream with equivalent flow to supply one injection well with 0.23 MMscfd would be assumed. For the high capacity plant, the assumed volumetric throughput is sufficient to supply 35 injection wells with 1.05 MMscfd per well.	0.23	35
H_2S content of recovered CO_2 stream, wt %	Low case based on Canadian projects. High case is based on average H_2S to CO_2 ratio for DEA separation in U.S. gas plants. High case also represents realistic maximum H_2S concentration, above which sour gas co-sequestration would be impractical from a geologic CO_2 sequestration perspective.	2	25
Total average H_2S recovered, MT/yr	Calculated based on average molecular weight of H_2S/CO_2 mixture, and the fraction of H_2S.	100	182,400
Total average CO_2 recovered, MT/yr	Calculated based on average molecular weight of H_2S/CO_2 mixture, and the fraction of CO_2.	4,300	547,100
Processes:	The acid gas stream is separated from oil and produced water in a 3-phase separator. The CO_2 is removed from the acid gas stream, together with H_2S, in an acid gas removal chemical absorption process. The CO_2/H_2S is separated from the rich solvent and is supplied for enhanced oil recovery injection.		
Major Equipment associated with CO_2 stream:	AGR absorber tower, amine solvent storage tanks, rich/lean heat exchanger, amine solvent regenerator/stripper, reboiler, condenser, pumps, blower. (Note: Multi-stage, intercooled compressor, glycol dehydrator are included in CO_2 transport model plant.)		
Operating Utilities	Steam, electricity, cooling water, chemicals makeup		
Utility and Chemical Requirements			
Steam (MMBtu/hr)	Steam requirements (e.g., amine regeneration reboiler) are not anticipated to change over existing production operations.	Negligible	Negligible
Electricity (kW)	Net decrease in overall electricity requirements due to shut-down or avoidance of downstream sulfur recovery operations	Net decrease	Net decrease
Water make-up for CO_2 plant, gpm	For the CO_2 recovery operations, water make-up is not expected to change over existing production operations.	Negligible	Negligible
Solvent make-up, gpm	For the CO_2 recovery operations, solvent make-up rates are not expected to change over existing production operations.	Negligible	Negligible
Soda Ash, lb/hr	For the CO_2 recovery operations, soda ash and other chemical additives (e.g., foam inhibitors, corrosion inhibitors) are not expected to change over existing production operations.	Negligible	Negligible
Air Emissions			
CO_2, lb/hr	Net decrease in CO_2 emissions to the atmosphere.	(1,095)	(166,600)
SOx, lb/hr	Slight decrease in overall SOx emissions is anticipated due to H_2S recovery and avoidance of downstream sulfur recovery operations.	Net decrease	Net decrease
Wastes Generated			
Regenerator Sludge, lb/hr	For the CO_2 recovery operations, regenerator sludge generation/disposal rates are not expected to change over existing production operations.	Negligible	Negligible
Spent carbon, lb/hr	For the CO_2 recovery operations, spent carbon rates are not expected to change over existing production operations.	Negligible	Negligible

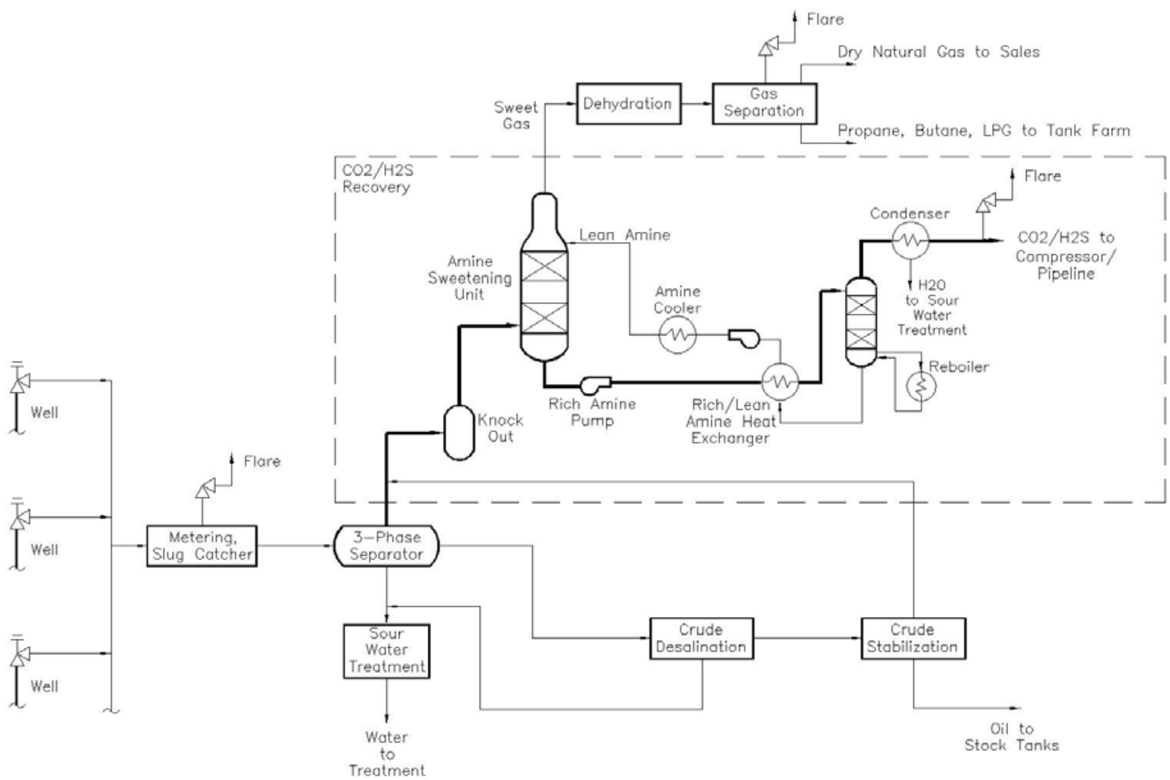

Figure 2-14. Schematic Diagram of Sour Associated Gas CO_2/H_2S Capture

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2.6 MODEL PROJECT SUMMARY TABLES

2.6.1.1 Carbon Sequestration

Table 2-33 provides a summary of the individual projects rates of CO_2 capture, transport or sequestration in metric tons (MT).

Table 2-33. Summary of Carbon Sequestration Rates per Model Project

Technology/Project Type	CO_2 Captured, Transported or Sequestered per Project (Field Validation-Scale, MT/Year)	CO_2 Captured, Transported or Sequestered per Project (Commercial-Scale, MT/Year)
Post-Combustion CO_2 Capture	74,825	2,238,910
CO_2 Compression and Transport (trucking)	36,500	0
CO_2 Compression and Transport (pipeline)	0	910,600
Coal Seam Sequestration	11,680	910,600
Enhanced Oil Recovery (EOR) Sequestration	4,380	809,209
Saline Formation Sequestration	13,140	909,100
Basalt Formation Sequestration	2,720	453,600
Terrestrial –Forestation Sequestration	3,630	90,720
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	3,036,800
Co-Sequestration CO_2/H_2S Capture: Sour Gas Associated for EOR or Saline Formation	4,380	547,500

2.6.1.2 Land Requirements

Table 2-34 provides a summary of the land requirements and how much land would be disturbed by individual projects at the field validation-scale and commercial-scale.

Table 2-34. Summary of Land Requirements and Disturbance per Project

Technology/ Project Type	Total Project Acreage per Project (Field Validation-Scale)	Total Project Acreage Disturbed per Project (Field Validation-Scale)	Total Project Acreage per Project (Commercial-Scale)	Total Project Acreage Disturbed per Project (Commercial-Scale)
Post-Combustion CO_2 Capture	5	5	60	60
CO_2 Compression and Transport (trucking)	0	0	0	0
CO_2 Compression and Transport (pipeline)	3.5	3.5	141	141
Coal Seam Sequestration	90	19	1,500	244
Enhanced Oil Recovery (EOR) Sequestration	135	15	2,880	686
Saline Formation Sequestration	92	9	2,750	291
Basalt Formation Sequestration	59	16	2,600	166
Terrestrial –Forestation Sequestration	500	0	10,000	0
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	30	30
Co-Sequestration CO_2/H_2S Capture: Sour Gas Associated for EOR or Saline Formation	1	1	15	15

2.6.1.3 Operational Chemical Requirements

Table 2-35 provides a summary of the annual chemical requirements for individual projects at the field validation-scale and commercial-scale. Rates of chemical use per metric ton of CO_2 captured and transported are provided in Table 2-36.

Table 2-35. Summary of Chemical Requirements per Project

Technology/ Project Type	Aqueous Solvent (gal/year) per Project (Field Validation-Scale)	Aqueous Solvent (gal/year) per Project (Commercial -Scale)	Soda Ash (lbs/year) per Project (Field Validation-Scale)	Soda Ash (lbs/year) per Project (Commercial -Scale)	Lubricating Oil (gal/year) per Project (Field Validation-Scale)	Lubricating Oil (gal/year) per Project (Commercial -Scale)
Post-Combustion CO_2 Capture	181,040	5,430,470	464,280	18,937,160	0	0
CO_2 Compression and Transport (trucking)	0	0	0	0	438	0
CO_2 Compression and Transport (pipeline)	0	0	0	0	0	56,940
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	7,295,255	0	18,746,400	0	0

Table 2-36. Chemical Use per Metric Ton of CO_2 Captured or Transported

Technology/ Project Type	Aqueous Solvent Use per MT CO_2 Captured/ Transported (Gal/MT)	Soda Ash Use per MT CO_2 Captured/ Transported (lbs/MT)	Soda Ash Use per MT CO_2 Captured/ Transported (lbs/MT)
Post-Combustion CO_2 Capture	2.4	8.5	*NA*
CO_2 Compression and Transport (trucking)	NA	NA	*0.01*
CO_2 Compression and Transport (pipeline)	NA	NA	*0.06*
Co-Sequestration CO_2/H_2S Capture: IGCC Based	2.4	6.2	*NA*

Note: All based on commercial-scale project except for Compression and Transport by Trucking

2.6.1.4 Well Installation

Table 2-37 provides a summary of the well installation requirements for individual projects at the field validation-scale and commercial-scale.

Table 2-37. Summary of Injection and Monitoring Wells Installed per Project and Alternative

Technology/Project Type	Injection Wells per Project (Field Validation-Scale)	Monitoring Wells (Field Validation-Scale)	Injection Wells per Project (Commercial-Scale)	Monitoring Wells per Project (Commercial-Scale)
Coal Seam	1	1	12	8
Enhanced Oil Recovery (EOR)	1	1	35	20
Saline Formation	1	1	3	8
Basalt Formation	1	3	12	10

Note: Additional production wells would also be installed for related resource recovery, such as under ECBM, EOR, EGR.

2.6.1.5 Waste Generation

Table 2-38 and Table 2-42 provide summaries of wastes (used oil, well cuttings, wastewater, sludge, and spent carbon) generated by individual projects at the field validation-scale and commercial-scale. The tables also summarize the collective amounts of the wastes generated under each alternative. Table 2-40 provides a comparison of wastes generated for each process relative to the amount of CO_2 captured, transported or sequestered.

Table 2-38. Oil and Well Drillings Generated Per Project and Alternative

Technology/ Project Type	Used Oil (gal/year) per Project (Field Validation-Scale)	Used Oil (gal/year) per Project (Commercial-Scale)	Well-Drill Cuttings (cu. Ft) per Project (Field Validation-Scale)	Well-Drill Cuttings (cu. Ft) per Project (Commercial-Scale)
CO_2 Compression and Transport (trucking)	120	0	0	0
CO_2 Compression and Transport (pipeline)	0	5,640	0	0
Coal Seam	2.98	59.5	3,472	34,920
Enhanced Oil Recovery (EOR)	0	0	4,800	268,000
Saline Formation	0	0	4,200	58,800
Basalt Formation	0	0	4,200	38,400

Table 2-39. Wastewater, Sludge and Carbon Waste Generation Per Project and Alternative

Technology/ Project Type	Wastewater (gal/hour) per Project (Field Validation-Scale)	Waste-water (gal/hour) per Project (Commercial-Scale)	Reclaimer Sludge (lbs/hr) per Project (Field Validation-Scale)	Reclaimer Sludge (lbs/hr) per Project (Commercial-Scale)	Spent Carbon (lb/hr) per Project (Field Validation-Scale)	Spent Carbon (lb/hr) per Project (Commercial-Scale)
Post-Combustion CO_2 Capture	0	0	50	1,485	1.5	45
CO_2 Compression and Transport (pipeline)	24	348	0	0	0	0
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	0	2,010	0	60
Coal Seam	2.98	59.5	0	0	0	0

Table 2-40. Wastes Generated Per Metric Ton CO_2 Captured/Transported/Sequestered

Technology/ Project Type	Used Oil Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Wastewater Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Reclaimer Sludge Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)	Spent Carbon Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)
Post-Combustion CO_2 Capture	0	0	54.4	*0.2*
CO_2 Compression and Transport (trucking)	0.003	0	0	*0*

Technology/ Project Type	**Used Oil Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)**	**Wastewater Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)**	**Reclaimer Sludge Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)**	**Spent Carbon Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)**
CO_2 Compression and Transport (pipeline)	0.006	3.3	0	*0*
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	5.8	*0*
Coal Seam	<0.0001	0	0	0

2.6.1.6 Air Emissions

Table 2-41 provides a summary of air emissions associated with compression and transport of CO_2. Heating units associated with injection of CO_2 at geologic sequestration sites also generate air emissions. These rates are summarized in Table 2-42.

Table 2-41. Air Emissions Relating to Compression and Transport Options

Parameter	**Compression and Trucking (lb/hour)**	**Compression and Pipeline (lb/hour)**	**Trucking (lbs/MT CO_2 conveyed)**	***Pipeline (lbs/MT CO_2 conveyed)***
CO_2	315	17,190	37.8	*165.4*
CO	1.90	60	0.23	*0.57*
CH_4	2.31	227	0.28	*2.18*
NOx	5.3	495	0.64	*4.76*
VOC	*0.2*	*19*	*0.02*	*0.18*

Table 2-42. Air Emissions Relating to Heating Units at Sequestration Sites

Parameter	**Coal Seam, Field Validation-Scale (lbs/hour)**	**Coal Seam, Commercial-Scale (lbs/hour)**	**Saline Formation, Field Validation-Scale (lbs/hour)**	**Saline Formation, Commercial-Scale (lbs/hour)**
CO_2	7.3	576.7	8.4	*587.2*
CO	<0.01	0.13	<0.01	*0.13*
CH_4	<0.01	0.01	<0.01	*0.01*
NOx	0.01	0.52	0.01	*0.63*
VOC	<0.01	0.01	<0.01	*0.02*
PM	<0.01	0.05	<0.01	0.05

2.7 REGULATORY FRAMEWORK AND PERMITTING

While large numbers of federal regulations in the U.S. deal with air emissions from industrial and energy generation facilities, to date none of these U.S. regulations currently govern CO_2 emissions into the atmosphere. Only the inventory list for the Toxic Substances Control Act (TSCA) of 1976, the NIOSH confined space hazard classification system, and the Federal Emergency Management Agency's (FEMA) hazardous materials guide treat CO_2 as a hazardous substance to the extent that any concentrated, pressurized, or cryogenic gas poses a danger. In all cases, it is included in the least hazardous category (Benson, 2002).

Federal and state authorities regulate CO_2 for many different purposes, including occupational safety and health, ventilation and indoor air quality, confined-space hazard and fire suppression, transportation, as a respiratory gas and food additive, and for animal anesthesia. Federal occupational safety and health regulations set three limits:

- 0.5 percent or 5,000 ppm for an average 8-hour day or 40-hour week.
- 3 percent or 30,000 ppm for an average short-term 15-minute exposure limit.
- 4 percent or 40,000 ppm for the maximum instantaneous exposure limit above which is considered immediately dangerous to life and health.

Most industrial and safety regulations for CO_2 focus on engineering controls and specifications for transportation, storage containers, and pipelines. Surface risks of CO_2 exposure are typically handled by State environmental health and safety regulatory agencies (Benson, 2002).

Some examples of federal agencies having codes of federal regulations (CFRs) relating to CO_2 include the following (Benson, 2002):

- Office of Pipeline Safety (OPS): gas or hazardous liquid regulations for engineering safety controls on pipelines.
- Department of Transportation (DOT): general requirements for transportation of materials.
- Occupational Safety and Health Administration (OSHA): air contaminant exposure limits, compressed breathing gas limits, confined space hazards environmental controls, and fire suppressants engineering controls and employee training.
- Mine Safety and Health Administration (MSHA): air contaminant exposure limits for underground and surface mines.
- National Institute of Occupational Safety and Health (NIOSH): compressed breathing gas limits for respirators and self-contained breathing apparatus.
- Federal Aviation Administration (FAA): ventilation air contaminant in airplane cabins.
- Food and Drug Administration (FDA): food substance and medical gas requirements.

Although CO_2 is not regulated at the federal level as an air emission, and other federal regulations are somewhat limited and generally focused on specific CO_2 applications, as described above, there are a number of key pieces of existing federal legislation that could affect carbon sequestration projects overall. Some of these may include, but are not limited to, the following:

- Clean Water Act (CWA, 1977): Sets the standard of nondegradation of the beneficial uses of water. Requires control of oxygen-demanding organic matter and suspended solids in the effluents discharged (as wastewater) from point and non-point sources. Uses area control or performance standards, such as requiring Best Management Practices, or operational activities to minimize impacts to water quality.

- Safe Drinking Water Act (SDWA, 1974): Led to EPA's Underground Injection Control (UIC) Program, setting requirements for different class injection wells. Of the five classes of wells according to regulations established by the federal UIC program, Class I wells are the most stringent and refer to injection of municipal or industrial waste, including hazardous waste, below the deepest underground sources of drinking water.
- Clean Air Act (CAA, 1970, 1990): Programs issue permits for new (and in some cases existing) stationary sources of emissions so that the emissions will not exceed the national ambient air quality standards (NAAQS) set for the six criteria pollutants: sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone (and its precursors, nitrogen oxides and volatile organic compounds), and lead. Establishes New Source Review, New Source Performance Standards, hazardous air pollutant standards, operating permits, and acid rain controls. (Note: Although CO_2 is not a regulated pollutant in the CAA, there are other regulated pollutants associated with carbon sequestration projects, primarily in the capture and transmission segments, that could be affected by the CAA.)

The current regulatory structure for underground injection combines together the efforts of many different agencies and regulatory authorities. Many different federal and state regulations and agencies are charged with ensuring that materials are handled, transported, and injected in a safe and appropriate manner. Pipeline transport is regulated by the Department of Transportation, for instance, while many of the EHS regulations are set by OSHA and adopted and enforced by the states.

2.7.1 Underground Injection Control (UIC) Program

Underground injection activities on land and in state waters are regulated by the U.S. EPA, with primacy given to different state agencies. Permitting requirements vary by individual well class. The explicit goal of the UIC program is to protect current and potential sources of public drinking water. The movement of injectate into an Underground Source of Drinking Water (USDW) is explicitly prohibited in Class I and II wells, where a USDW is defined as an aquifer that has a total dissolved solids content of less than 10,000 mg/L (Brasier, 1996). UIC regulations do not, with the exception of hazardous waste Class I wells, specify any containment time for the injectate (Wilson, 2003).

Even within the same jurisdiction, the injection of identical fluids is treated differently, depending on their source. Produced brine from a hydrocarbon production operation and that from an industrial process fall under different well classes; are managed by different institutions; and are subject to different site characterization, construction, management, and reporting requirements. It is unclear now if CO_2-specific regulations would be integrated within the existing underground injection regulations or if, in the long run, an entirely different regulatory approach would be beneficial (Wilson, 2003)

Federal jurisdiction to regulate underground injection in the U.S. was established by the 1974 Safe Drinking Water Act. On land in the U.S., underground fluid injection is managed under the U.S. EPA's UIC program. The structure of regulations that currently govern underground injection activity consists of an overarching federal program, laid out in detail in 40 CFR 144-148. In states without UIC primacy, the EPA Regional Offices manage the programs. In several states, additional regulatory controls that are specific to local geology or operational practices are applied to specific injection practices, making particular states more restrictive than the minimum federal standards. The federal code divides injection wells into five specific classes based on where the injectate originates, the level of potential health and environmental harm, and where it is to be injected. Depending on the well class, different state agencies manage the permitting and monitoring of injection activities.

> The explicit goal of the UIC program is to protect current and potential sources of public drinking water.

Class I wells handle non-hazardous industrial wastes as well as hazardous industrial wastes and municipal waste waters. The state's department of the environment usually manages them. Class I hazardous wells are required to obtain a "no migration demonstration" as required by the Resource Conservation and Recovery Act. Class II wells handle wastes associated with hydrocarbon production and enhanced oil recovery and are, with few exceptions, managed by the state's department of oil and gas. In practice, depending on their source and specific regulatory exemptions, similar wastes are injected into both Class I and II wells, but with quite different permitting and operational requirements. H_2S injected in a Class I regime is considered a hazardous waste, but within a Class II regime, H_2S arising from natural gas extraction is not. State EH&S regulations, such as Texas' Rule 36, ensure that safety considerations are incorporated into acid gas injection (Wilson, 2004)

While the Class I Hazardous Program may be run through the state, operators of hazardous waste wells must receive approval of a "no-migration demonstration", as required by RCRA and granted through the regional EPA office in addition to their state or U.S. injection permit (Smith, 1996). The rules mandate zero contamination: if "movement of any contaminant into the USDW" is detected, corrective actions will be taken "as are necessary to prevent such movement" (40 CFR 144.12b). The no-migration petition requires operators to demonstrate using computational models that wastes will not migrate from the injection zone for at least 10,000 years, or will be rendered harmless, as demonstrated through chemical transformation modeling (Wilson, 2003).

Aside from prescribed well integrity tests, the current regulatory structure for underground injection is almost exclusively procedural rather than performance-based. That is, the regulations specify what an operator must do; for example, they specify how an injection well must be constructed rather than specifying and outcome, such as a maximum acceptable leak rate that must be achieved. There are no federal requirements for monitoring the actual movement of fluids within the injection zone, nor are there requirements for monitoring in overlying zones to detect leakage, with the exception of specific Class I hazardous wells, where this monitoring can be but rarely is specifically mandated.

While there have been few reported problems, it is difficult to assess the success of the program because there is little monitoring designed to assess the transport of injected fluids. Therefore, there are no studies comparing the fluid transport predictions made in the no-migration petitions with actual observations (Wilson, 2003).

In March 2007, EPA issued Final Guidance to assist EPA Regional and State and Tribal Underground Injection Control (UIC) Program Directors in processing permit applications for pilot projects designed to evaluate the technical issues associated with CO_2 injection as Class V experimental technology wells. The aim of this Final Guidance is to assist UIC Program Directors in evaluating permit applications and setting appropriate Class V experimental technology well permit conditions for pilot CO_2 injection projects (EPA, 2007).

Permits for pilot CO_2 geologic sequestration projects will be issued by State, Tribal, and EPA Regional UIC Program Directors under the authority of the Safe Drinking Water Act (SDWA) beginning by March 2009 for the validation phase. EPA expects that commercial-scale geologic sequestration efforts will commence around 2012 for the deployment phase (EPA, 2007).

In the Final Guidance, EPA determined that CO_2 geologic sequestration wells constructed and operated as part of either phase may qualify as Class V experimental technology wells provided they meet the definition of that term in 40 CFR 146.3 ("a technology which has not been proven feasible under the conditions in which it is being tested"). Class V experimental technology wells are intended to demonstrate unproven but promising technologies with the rationale that allowing the use of these wells encourages innovation. Under EPA's regulations an injection well that is being used to demonstrate a developing technology may be subject to more flexible, yet fully protective, technical standards than those designed for commercially operating facilities. While injection of fluids, including CO_2 into the subsurface, e.g. for EOR and EGR, is a long-standing practice, injection of CO_2 for geologic sequestration is an experimental application of this existing technology (EPA, 2007).

Depending on the specific circumstances, for purposes of the pilot projects, permitting CO_2 injection into deep saline formations, depleted hydrocarbon reservoirs, or basalt formations through Class V experimental technology wells may be appropriate. In addition, depending on the particular facts, CO_2 injection wells of pilot geologic sequestration projects that involve methane-depleted coalbeds, depleting natural CO_2 formations, and non-commercial gas fields may be appropriate for permitting as Class V experimental technology wells. CO_2 injection for EOR or EGR operations is a long-established technology, and these wells may continue to be permitted as Class II wells, and Class II permitting requirements would apply. However, if the injection of CO_2 through those wells is not associated with the enhanced recovery of oil or gas, these operations would then be considered for re-permitting as Class V experimental technology wells (EPA, 2007).

Although there are no Federal requirements written specifically for Class V experimental technology wells, there are applicable requirements for Class V wells generally (see 40 CFR 144.12, 144.24 to 144.27, and 40 CFR 144.79-.89). Federal UIC permitting requirements at 40 CFR Parts 144 and 146 should be considered and implemented and permit issuers should follow the requirements for public participation (40 CFR Part 124) (EPA, 2007).

2.7.2 Pipeline Regulations and Permitting

In the U.S. Department of Transportation (DOT), PHMSA - the Pipeline and Hazardous Materials Safety Administration has public responsibilities for safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines.

CO_2 pipelines are regulated as hazardous liquids pipelines. Federal regulatory approval is not ordinarily required for development of a new hazardous liquids pipeline, unless it will cross federal lands. Generally, state and local laws are the primary regulatory factors for construction of new hazardous liquid pipelines.

Types of permits that may be required for the construction of a CO_2 pipeline may include (but not limited to):

- State permit to operate and maintain a Hazardous Liquid Pipeline
- Wetland disturbance – under the Section 404 of the Clean Water Act. Pipelines that cross wetlands may qualify for the Nationwide-12 program.
- Air permits - Pumping Stations and Compression Stations are likely to require state air permits.
- NPDES permit – for stormwater related to construction activities.
- Soil Conservation – any local or state soil conservation district permits.
- Cross-border permit - the Secretary of State has the authority to issue Presidential Permits for cross-border liquid (water as well as petroleum product) pipelines and other cross-border infrastructure. The Office of International Energy and Commodity Policy receives and processes permit applications.

2.7.2.1 Pipeline Rights of Way

Most hazardous liquid and natural gas transmission pipelines are located underground in rights-of-way (ROW). A ROW consists of consecutive property easements acquired by, or granted to, the pipeline company. The ROW provides sufficient space to perform pipeline maintenance and inspections, as well as a clear zone where encroachments can be monitored and prevented.

The term “right(s)-of-way (ROW)” is used to describe the property or easement that pipeline operators secure in order to locate and maintain their pipeline. Operators generally obtain ROW by purchasing the property or acquiring an easement, by mutual negotiated agreement with a landowner, or through court-ordered condemnation procedures. Condemnation procedures are only carried out when specific types of pipelines are deemed by the courts to be necessary for public convenience.

2.7.2.1.1 ROW Agreements

ROW agreements typically specify the rights of the pipeline operator with respect to the property, as well as the ongoing above-ground use rights of the landowner. Additionally, ROW agreements may address issues such as:

- Single or multiple pipeline rights;
- Defined ROW width, which can vary from as small as the width of the pipeline to 50-feet or more;
- Rights for above ground facilities attached to the pipeline such as valves;
- Pipeline repair or modification constraints or considerations;
- Payment for original and continued use of the ROW;
- Damage award amounts appropriate for the property owner associated with original construction or future repairs/modifications;
- Access requirements for pipeline personnel, and;
- Requirements for pipeline removal upon termination of use by the pipeline operator.

2.7.2.1.2 ROW Special Considerations

A ROW is ordinarily sufficient for day-to-day operations of a pipeline, but is often insufficient for situations where pipeline repairs or expansions are planned. In such cases, the pipeline operator often has to renegotiate with a property owner for additional permanent and/or temporary work space.

Pipeline operators generally try to keep the ROW as free of physical encumbrances as possible in order to assure reasonable and frequent visual inspections of the pipeline from the air and ground. In addition, a clear ROW helps ensure ease of access for repair excavations.

These concerns must be balanced with the wishes of the landowner to maintain options for the ROW, including using the land for crops, grazing, parking and other uses. Limitations sometimes imposed on the landowner can include prohibitions against the installation of buildings, pools, trees and other physical structures.

Residential and commercial development in once-rural areas is encroaching on pipeline ROWs with increasing frequency. Encroachment implies safety concerns for local residents and for the physical integrity of the pipeline itself. To help prevent encroachment and excavation-related damage to pipelines, operators are required to post pipeline markers clearly and frequently along the length of the ROW. They must also communicate with residents along the ROW and establish liaison with local government and emergency officials (OPS, 2005).

2.7.2.2 Pipeline Safety Responsibilities

Pipeline operators are responsible for the assurance and management of safety in the operation of their energy transportation pipelines. Ensuring safety requires that operators consider every aspect of their pipeline operations, including:

- sound system design;
- selection and use of qualified materials;

- proper construction;
- thorough and adequate inspection, testing, maintenance and repair;
- continuous system monitoring and control;
- operations conducted by trained and qualified workers;
- implementation of damage prevention best practices;
- identification and mitigation of risks; and
- coordination and preparation for emergency response (OPS, 2005).

More information about the safety responsibilities of pipeline operators can be found at the Office of Pipeline Safety website at http://primis.phmsa.dot.gov/comm/SafetyResponsibilities.htm.

2.7.3 Coal Seam Sequestration Permitting Requirements

Given the large volumes of water associated with coal bed methane production and enhanced coal bed methane recovery from mineable coal seams, the water supply, treatment, and discharge aspects of a coal seam sequestration project will entail a significant portion of the project's permitting requirements. Some examples of the types of federal, state, and local water permits that may be required include the following (Montana DEQ, 2006):

- Section 404 of the Clean Water Act: discharge of dredged or fills material into the waters of the U.S..
- Clean Water Act, 33 USC 1341 Chapter 26: water pollution prevention and control.
- State water quality discharge permits.
- State Pollutant Discharge Elimination System (SPDES) permits: effluent guidelines limitations.
- State ground water pollution control system permit: facility-specific industrial dischargers.
- Surface water standards and procedures: rules.
- Mixing zones in surface and groundwater: rules.
- Nondegradation of water quality: rules.
- Short-term water quality standards for turbidity related to construction activity: permit.
- 401 Certification of USACE 404 permits.
- State permit for formation or off-channel containment pits storage of CBM produced water.
- State CBM general permits for temporary discharges for drought relief, and ground water quality characterization.
- State controlled groundwater area standards: production well standards, well log reports, water mitigation agreements, and groundwater monitoring and reporting requirements.
- State permit to appropriate groundwater.
- State permit for aquifer storage and retrieval wells.
- Water rights: issued by state natural resources agency, for beneficial uses of water from CBM operations.
- Local conservation district permits.
- Permit for proposed work in state streams, lakes, and wetlands.

In addition to the ground water and surface water potential permitting requirements associated with enhanced coal bed methane geologic sequestration projects, the other major permitting focus would likely be on the underground CO_2 injection. As discussed previously in Section 2.6.1, the Federal Safe Drinking Water Act established the UIC program to provide safeguards so that injection wells do not endanger current and future underground sources of drinking water. The EPA has the authority to control underground drinking water sources, with a majority of states having primacy for issuing UIC permits.

Injection wells related to oil and gas operations are known as Class II wells. Class II wells are those wells utilized for injection for the purpose of: a) enhanced recovery of oil and gas; b) injection for storage of hydrocarbons liquid, at standard temperature and pressure; and c) the disposal of fluids which are brought to the surface in connection with natural gas storage operations or conventional production of oil and gas. Thus, ECBM injection wells would likely be classified as Class II UIC wells.

2.7.4 Enhanced Oil Recovery Sequestration Permitting Requirements

In addition to the Class II injection well UIC permit, there are a number of other potential federal, state, and local permits, approvals, and authorizing actions that may be required for an enhanced oil recovery CO_2 geologic sequestration project. Some of these may include, but are not limited to, the following (DOI BLM, 2005):

- Onshore oil and gas orders: Permitting of operations (drilling - applications for permits to drill, completion, abandonment), drilling operations, site security, measurement of oil, flaring of gas, produced water disposal; includes wells, associated facilities, and roads.
- Oil and gas rules and regulations: State permits for drilling operations, safety regulations, pit permits, product measurement, and authorization of flaring, for wells and related facilities.
- State authorization of activities on state land: Approval of oil and gas leases, rights-of-way, temporary use permits, and developments on state land, for all facilities.
- RCRA: Permits for treatment, storage, or disposal of hazardous waste.
- Clean Water Act: Spill prevention, control, and countermeasure for transfer and storage of petroleum and petroleum fuels.
- State air quality permits: Permits for new or modified sources; prevention of significant deterioration, if applicable; control of HAPs, hydrogen sulfide, and VOCs; for all stationary fuel-burning sources, tanks, separators, dehydrators, and compressors.

2.7.5 Saline Formation Sequestration Permitting Requirements

As discussed previously for enhanced coal bed methane and enhanced oil recovery CO_2 geologic sequestration projects, respectively, existing UIC program regulations have specific requirements for the injection of fluids and gases in Class II wells associated with oil and gas production. These rules and regulations could readily be made to directly apply to CO_2 injection for EOR and ECBM purposes as part of a CO_2 geologic sequestration project.

However, there have been no commercial-scale applications of CO_2 geologic sequestration in saline formations in the U.S. to date, and the non-EOR injection of CO_2 in saline formations for sequestration purposes is not directly covered by the existing UIC program rules. Various potential regulatory options exist to cover non-EOR CO_2 injection wells, including incorporating existing natural gas storage statutes and regulatory frameworks, inclusion under Class I or Class V of the UIC program, reclassifying such wells as a subclass of Class II, or the creation of a new UIC classification (IOGCC, 2005).

Some view that among the five classes of injection wells, the most relevant to CO_2 injection into saline formations is the Class I wells (Tsang, 2004). The regulations for Class I wells are stringent and specific, while they are more flexible for Class II wells.

2.7.6 Co-Sequestration/IGCC Permitting Requirements

As there are only two fully integrated IGCC plants developed primarily for electricity generation in operation in the U.S., it is likely that any co-sequestration projects that inject CO_2 and H_2S acid gas developed in the U.S. by the 2013 time frame will involve a new, "greenfield" IGCC facility. Therefore, the various potential regulatory and permitting issues with developing a new IGCC plant with carbon capture and sequestration are described here. Some of these regulatory issues and permitting requirements could include, but not limited to, the following (UTBEG, 2005; Florida DEP, 2006; EPA 2006):

Utility Approvals

- Certificate of Public Convenience and Necessity: Approval by the state public utility or public service commission, certifying that the proposed IGCC plant is economical and meets the public need for additional efficient power generation.
- Facility siting approval: Approval by the state siting board that the proposed site is appropriate and the best among all alternatives with regard to environmental and other impacts.

Air Permitting and Regulatory Issues

- Fuel handling and preparation NSR permit for PM emissions (fugitive or point source); emission limits and/or PM control technology requirements.
- Gasifier exhaust particulate removal NSR permit for PM emissions; emission limits and/or PM control technology requirements.
- Combined cycle generation stack emissions NSR permit for NOx, CO, and VOC emissions; emission limits and control technology requirements.
- Potential cooling tower drift air emissions NSR permit for PM emissions, or demonstration of no contaminant release.
- Air separator unit stack emissions NSR permit for NOx emissions; emission limits and/or control technology requirements.
- Compliance assurance monitoring (CAM) for combined cycle generation stack emissions.
- NESHAP standard for hazardous air pollutants (HAPs).
- NSPS for combined cycle combustion turbine emissions.

Water Permitting and Regulatory Issues

- Groundwater management districts (including local requirements for sustainability) and surface water rights permits.
- Gasifier, and production water (fuel slurry mixture and steam generator), wastewater treatment and discharges: NPDES, pre-treatment and discharge to publicly owned treatment works (POTW), and/or UIC Class I discharge well permits.
- Cooling tower blowdown wastewater treatment: NPDES or POTW pre-treatment permits.
- Stormwater discharge of contaminated runoff: NPDES stormwater permits for construction and operation.

Waste Disposal

- Gasifier solid wastes: slag non-hazardous waste landfill permit or marketable byproduct, or ash potential RCRA hazardous waste requiring permit for storage and/or disposal.
- Gasifier exhaust particulate matter solid waste non-hazardous landfill permit.

- TRI annual reporting (e.g., for acid aerosols, ammonia, barium, chromium, HF, lead, manganese, mercury, nickel, nitrates, vanadium, and zinc).

Underground Injection/Sequestration of CO_2/H_2S

- UIC injection well Class I, Class II, or new classification permit.

2.8 FATE AND TRANSPORT OF CO_2 INJECTED INTO GEOLOGIC FORMATIONS

This section describes the predicted mobility and fate of CO_2 sequestered in geologic formations, based on existing field data, research and predictive modeling. Because data on the fate and transport of CO_2 in geologic formations is limited, this section does not cover fate and transport for all sequestration technologies. Therefore, the project examples, published papers and/or case studies provided here can illustrate some of the preliminary results of field studies or provide predictions regarding the general fate and transport of CO_2 in geologic formations.

Based on the body of work summarized and documented in the following sections, a number of general observations and conclusions can be made regarding the fate and transport of sequestered CO_2. These include the following:

- Depending on the type of formation involved, it appears that the maximum radial extent of the CO_2 plume from the injection well(s) should be on the order of 5-10 kilometers or less (< ~3-6 miles).
- For saline formations, significant dissolution of CO_2 in the formation water will help to limit the extent of the CO_2 phase plume, particularly in the 100+ year time frame.
- Geologic sequestration projects with well characterized formations, and well designed, constructed, operated, and monitored injection and post-operations systems, should be able to exhibit essentially no significant leakage.
- The greatest risk of leakage appears to be associated with abandoned wells.
- There are monitoring and mitigation technologies currently available that should be able to detect and remediate leaks of any major significance.

2.8.1 Overview of Fate and Transport Mechanisms

The type of geologic formation involved has a great degree of influence on carbon storage and transport. For example, coal seams have high potential for adsorbing CO_2 on coal surfaces. However, coal tends to swell in volume as it adsorbs CO_2, which can then restrict the flow of CO_2 into the formation. Oil and gas formations result from the presence of a structural or stratigraphic trap, which has been shown to reliably retain injected CO_2 (in the absence of leakage pathways). Saline formations suitable for carbon sequestration would need to be overlain by a reliable caprock. Basalt formations have the potential to mineralize injected CO_2 (forming carbonate minerals) that may effectively and permanently isolate it from the atmosphere, although large-scale field testing is required to confirm this potential.

Leakage of CO_2 from underground formations into the atmosphere or into overlying water supply aquifers is the leading concern associated geologic sequestration technology. The mechanism for leakage is highly dependent on the geological conditions of the storage structure and the uncertainties surrounding potential releases are great (Yammaoto et. al., 2004).

Porous formations themselves create a path for CO_2, but discontinuity of the formation, such as fractures or faults are more influential to the total permeability of the formation. Pathways and mechanisms for leakage can include:

- Failure of seal formations near the borehole (corrosion of formation rock, the casings, and the cement in the annulus).
- Leak through abandoned boreholes and wells.
- CO_2 migration through the seal formation due to its innate permeability.
- Seal structure failure by formation stress and pressure change caused by injection.
- Seal failure by external forces, such as tectonic forces, stress change caused by subsidence and sedimentation, earthquakes, etc (Yammaoto et. al., 2004).

Sites should be adequately characterized during the early project planning stage to identify any potential leakage pathways.

Overall, the fate and transport of CO_2 in geologic formations is highly dependent on site-specific conditions, such as geologic conditions, leakage pathways, chemical trapping mechanism, and formation pressure resulting from injection rates.

2.8.2 Fate and Transport – Transport Mechanisms and Predictive Modeling

2.8.2.1 "Storage Retention Time of CO_2 in Sedimentary Basins; Examples from Petroleum Systems" (Bradshaw, et al, 2005)

Thousands of billions of barrels of hydrocarbons have been trapped and stored in geological formations in sedimentary basins for 10s to 100s of millions of years, as has substantial volumes of CO_2 that has been generated through natural processes. If the same rigorous methods, technology and skills that are used to explore for, find, and produce hydrocarbon accumulations are now used for finding safe and secure storage sites for CO_2, the traps so identified can be expected to contain the CO_2 after injection for similar periods of time as that in which hydrocarbons and CO_2 have been stored in the natural environment.

It is anticipated that many of the risks and uncertainties associated with leakage from appropriately selected storage sites will become evident early in a project, long before significant volumes are stored. The most critical factor associated with leakage to the surface on human timescales will be from well bores rather than natural subsurface processes. Well bores can be monitored, maintained and remediation performed if required either before or during the injection operation, and as such this risk can be controlled. A remediation operation can readily be achieved within a 3 month period, which is insignificant in terms of leakage volumes when considered over the timeframe of either an injection period, or the total storage time. If injection sites are appropriately selected down dip from structural culminations, or hydrodynamic/solution traps are utilized as opposed to direct injection into depleted fields, then the likelihood of leakage failure from wells will be very much lower again. In such cases, injection pressures will have dissipated before the CO_2 gets to a leakage point, significant amounts of CO_2 will be trapped in closures with no well penetrations, and CO_2 will have dissolved into the formation water.

The timing of when leakage due to natural subsurface processes could occur post the injection period must also be borne in mind. If injection sites are chosen down dip from either structural culminations with well penetrations, faults or basin edges, then the time to migrate to leakage points could often be on the order of 1000s of years. Even if vertical migration results in the CO_2 permeating through imperfect seals, then there still will be tortuous pathways that the CO_2 will have to migrate through to reach the surface, and again this may be on the order of 1000s of years.

The above discussion suggests that leakage to the surface in human timeframes from appropriately selected storage sites will only occur in substantial volumes through old well bores that are not maintained and remediated, rather than through natural subsurface processes, and even then, there may be significant delay times before leakage to the atmosphere occurs. This suggests that future research effort should strongly focus on old well bores and how to make them safe and secure with non-corrosive components and materials, and the potential impact of subsurface leakage (out of the primary formation into a secondary shallower formation) and potential contamination effects that occur to subsurface resources (e.g., groundwater).

2.8.2.2 "Area of Review: How Large is Large Enough for Carbon Storage?" (Nicot, et al, 2006)

The Underground Injection Control (UIC) program defines the area of review (AOR) as the area surrounding an injection well described according to the criteria set forth in Section 146.06, or in the case of an area permit the project area plus a circumscribing area the width of which is either ¼ of a mile or a number calculated according to the criteria set forth in Section 146.06. Within the AOR, before starting any injection, an operator must identify all wells penetrating the injection zone or the confining zone and assess their status for possible corrective action. The overarching purpose of the AOR is protection of drinking water resources due to pressure buildup in the injection zone. Underground sources of drinking water (USDW) are defined as a formation with water quality below 10,000 ppm total dissolved solids. The AOR should be determined for each well or field through either a zone of endangering influence (ZEI) or a fixed radius, which cannot be smaller than ¼ mile. The radius of the ZEI is calculated as the lateral distance in which the pressures in the injection zone may cause migration of the injection and/or formation fluid into a USDW.

In Texas, as in most of the U.S., the fixed radius method is overwhelmingly used and is ¼ mile for Class II wells and 2.5 miles for Class I wells. Current requirements from the Railroad Commission of Texas for Class II wells include making best efforts to identify all wells in a ¼ mile radius of the proposed injection well and to provide evidence that all abandoned wells intersecting the injection formation have been plugged. The Texas Gulf Coast is an attractive target for carbon storage. Stacked sand-shale layers provide large potential storage volumes and in-depth leakage protection. However, multiple perforations resulting from intensive hydrocarbon exploration and production have weakened seal integrity in many favorable locations. If the ultimate goal of carbon storage is to isolate large volumes of CO_2 for hundreds to thousands of years, plume migration will encounter inadequately completed wells miles away from the injection zone. Even wells abandoned to current standards cannot be guaranteed leak-free in the long term.

Although the AOR has been traditionally defined by a fixed radius, with the strong regulatory requirement that the injectate stays within the injection layer, based on a "no-migration rule", buoyancy is a major characteristic of CO_2 that introduces a third dimension into the AOR process. Geological mapping was used to characterize some of the typical structural traps associated with the southern Texas gulf coast's progradational packages and growth fault zones, and well locations and salt dome footprints in the Corpus Christi and Houston areas. Likely CO_2 migration pathways and contacted volume of a migrating plume were determined, with the latter being potentially as large as a fault compartment with dimensions of up to 13 miles by 13 miles. However, the contacted volume is ultimately a function of the total injected volume, and the specifics of each project should dictate the dimensions of the zone of endangering influence. An option viable for the Texas gulf coast to reduce geologic uncertainty, to decrease the impact of wells, and to limit the amount of information to be collected is to inject CO_2 below the maximum penetration of most wells.

2.8.2.3 "Modeling the Sequestration of CO_2 in Deep Geological Formations" (Saripalli, et al, 2005)

Modeling the injection of CO_2 and its sequestration will require simulations of a multi-well injection system in a large formation field. However, modeling at the injection well scale is a necessary prerequisite to formation scale modeling. The models effectively simulate deep-well injection of water-immiscible, gaseous, or supercritical CO_2. The effect of pertinent fluid, formation, and operational characteristics on the deep-well injection of CO_2 was investigated. Formation permeability, porosity, injection rate and pressure, and dissolution of CO_2 influence the growth and ultimate distribution of the CO_2 phase. Deep-well injection of CO_2 is a multiphase flow phenomenon, where a slightly compressible supercritical fluid drives water radially outward, and also migrates upward due to buoyancy.

The CO_2 bubble growing during injection simultaneously dissolves in the formation waters and migrates upwards due to buoyancy. As a result, the CO_2 bubble recedes radially inwards, and floats toward the top confining layers. A set of simulations was run where CO_2 was injected for a period of approximately 3 years, and then allowed to dissolve and float. Immiscible CO_2-water contact, after the completion of buoyant floating and equilibrium dissolution, creates a region above this contact rich in free-phase CO_2 distributed radially. The injected CO_2 phase recedes radially and floats vertically upward, after a part of it being dissolved in the formation water. In the longer term, a part of this dissolved carbon may be permanently sequestered as a mineral phase, with the remaining mass being redistributed by dilution among the formation waters via advection and diffusion. The thin, free phase CO_2 layer floating at the top will serve as a source for diffusive flux into the formation waters, as well as potential escape into the overlying aquifer via fractures and high permeability conductive zones within the caprock. While the model can simulate the basic features of a typical CO_2 deep-well injection operation, it is based on the assumptions of uniform formation properties, and instantaneous dissolution of CO_2, which is likely to be a rate limited process. Apart from these limitations, these analytical approaches to the modeling of deep-well injection were shown to agree with earlier field data in natural gas storage applications.

After approximately 3 years of CO_2 injection, at a rate of approximately 150,000 tons/year, into a 160 meters thick formation, the radial distance from the injection well of the free-phase CO_2 bubble ranged from approximately 3–10 kilometers (or 2-6 miles), for formation porosities ranging from 10-30 percent. For the 30 percent porosity base case, free-phase CO_2 bubble radial distances ranged from approximately 3-18 kilometers (or 2-11 miles), for CO_2 injection rates ranging from approximately 150,000 to 1.5 million tons/year.

2.8.2.4 "Quantitative Estimation of CO_2 Leakage from Geological Storage: Analytical Models, Numeric Models and Data Needs" (M. Celia, et.al., 2004)

Comprehensive risk assessments are required to determine the overall effectiveness and potential environmental consequences of geologic carbon sequestration. An important part of these risk assessments are analyses of potential leakage of injected CO_2 from the formations in which it is injected into the atmosphere or other formations. Such leakage is a concern because it may contaminate existing energy, mineral, and/or groundwater resources, it may pose a hazard at the ground surface, and contribute to increased concentrations of CO_2 in the atmosphere.

Potential leakage pathways include diffusion across caprock formations, leakage through natural faults or fractures, and leakage through man-made features such as wells. The purpose of this paper was to develop large-scale mathematical modeling tools that can quantify potential CO_2 leakage along existing wells. The authors studied well locations in the Alberta basin to determine the spatial characteristics of well locations in a mature basin.

Injection of CO_2 into mature sedimentary basins could produce plumes that contact tens to hundreds of existing wells. Due to the fact that there is a broad range of length scales to be considered; a wide array of models is required that range from models of the geochemical degradation of well cements (cement plugs used to seal off abandoned wells) to models that include hundreds of existing wells over hundreds of square miles. Numerical models require very fine levels of detail, which would make modeling the effects of hundreds of wells a massive computational requirement. Therefore, in situations with large numbers of wells analytical solutions could be employed as a simplified approach.

The authors utilized an analytical approach to develop a mathematical technique capable of modeling a situation that encompassed a large number of wells over a large surface area, such as the Alberta basin.

This specific study of the Alberta basin showed that in areas with a high density of wells, an average of 240 wells would be contacted by a typical CO_2 plume that radiates on the order of 3.1 miles. However in background regions where wells are more sparsely located, approximately 20 wells would be contacted on average.

Because wells are continuous features, leakage through a well can result in leaked fluid contacting all formations along the well, as it proceeds toward the land surface and eventually reaches the atmosphere. The availability of permeable upper layers along the vertical column may attenuate the leakage as it proceeds.

The authors conducted models to determine relative leakage rates over time (27 years) where the leakage rate was expressed as a fraction of the CO_2 injection rate, normalized by the ratio of the permeability of the leaky well to the permeability in the injection formation. Their results indicate that the higher leakage rates in the leaky well induce stronger local decreases in pressure around the leaky well, which then induces increased brine flow into the leaky well. This “upconing” of brine into the well causes a much more gradual rise in the leakage rate for the CO_2, which corresponds to a much longer time period of two-fluid flow in the leaky well. The upconing around the leaky well causes a simultaneous flow of brine and CO_2 through the well, which has implications for the degradation of well materials. Well cement will degrade from acidified brine flowing past or through the cement. At higher CO_2/brine flow rates, the stronger upconing produces longer periods of acidified brine flow, which can lead to faster and more persistent degradation of well cements. This behavior provides a positive, non-linear feedback between the degradation and flow processes.

2.8.2.5 Multiphase CO_2 Flow, Transport and Sequestration in the Powder River Basin, Wyoming, USA” (McPherson, et al, 2000)

In this paper, the authors consider: (1) aqueous trapping, referring to the trapping of CO_2 by forming a groundwater plus CO_2 solution, leading to carbonic acid and dissociated ions, and (2) hydrodynamic or stratigraphic trapping: CO_2 moving into zones of high storage (porosity) and permeability, surrounded and trapped by zones of low permeability that restrict CO_2 escape. The Powder River Basin in Wyoming is a good example of a basin dominated by clastic units with interlayered carbonate formations. It was chosen for this CO_2 sequestration study because it is a typical intracontinental sedimentary basin, especially with regard to aquifer types, and its dominantly clastic stratigraphy and simple structure are helping to isolate relevant processes by minimizing complications due to structure and carbonates.

Numerical modeling analyses were conducted to evaluate flow, transport, and storage of groundwater and CO_2 in candidate aquifers of the Powder River Basin. In these numerical model simulations of the Powder River Basin, separate phase CO_2 was injected into the Fox Hills Sandstone at approximately 1,800 meters depth. By 750 years simulation time, saturation of separate phase CO_2 has decreased to less than 2 percent. Most of the CO_2 in the source has migrated away from the storage area and subsequently partitioned into solution in groundwater. Over the course of 1,000 years, CO_2 (both separate and dissolved phases) have migrated approximately 23 kilometers (or approximately 14 miles) away from the storage area. No CO_2 reached the ground surface within 1,000 years in any of the case study simulations. The primary general conclusion drawn from this modeling study is that regional scale sedimentary basin aquifers are viable candidates for CO_2 sequestration for time-scales of 103 years.

2.8.2.6 “Subsurface Sensitivity Study of Geologic CO_2 Sequestration in Saline Formations” (Flett, et.al., 2003)

Researchers with ChevronTexaco and Curtin University, Australia, conducted computer modeling of CO_2 in saline formations, assuming a high injection rate, under varying conditions. The model assumed a CO_2 injection rate of 120 mmscfd (6227 metric tons per day) equally distributed among 3 injector wells at a true vertical depth of approximately 7000 feet. Under the model, CO_2 would be injected for 30 years, after which only monitoring would occur. The key parameters that were varied in this screening study were:

- CO_2 solubility in brine
- Drainage relative to permeability curves
- Relative permeability hysteresis using:
    - pore size distribution parameter
    - Land's trapping constant
- Crestal fault leak/seal
- Saline formation volume

The study developed metrics for measuring sensitivity of a sequestration project to risk, estimated at different project times, via:

- The distance of injected CO_2 away from the injected location
- The volume of free CO_2 that exists in the formation in the CO_2 rich phase (i.e., not dissolved in formation waters)
- The size of the plume of CO_2 migrating up dip.
- The pressure change associated with the CO_2 injection at the crestal fault location.

These four measurements were developed to provide insight into the success of the proposed project during injection time. The migration distance of CO_2 is a key measure to show the probability of a plume reaching a leak point in the form of a non-sealing fault. The volume of free gas in the formation represents the amount of CO_2 not trapped by dissolution trapping and hence the amount of gas that remains as a potential leakage risk. The size of migration plume is a key measure of the success of gas trapping as permanent trapping mechanism and the risk associated with a volume of gas migrating to a leak point. The pressure change at the fault, relative to the base case model, gives a representation of the sensitivities associated with a pressure sensitive seal at a fault and potential risk of leakage through the fault to surface.

General Results and Observations:

- Low gas trapping and small formation size increase the migration distance of the gas. High gas trapping and larger formation size limits the extent of gas migration.
- The volume of the CO_2 plume has a strong relation to migration distance traveled. The larger the plume, the further the plume traveled up dip.

All cases after 30 years showed a migration distance of the gas from the injection points at approximately 2-3 kilometers (1.2 – 1.9 miles). The "very low gas trapping" case showed the highest migration of the gas from the injection points at the 8000 year mark at over 12 kilometers (7.5 miles). The case with "very high gas trapping", in contrast, showed a migration distance of only 3.5-4 kilometers (2.2 – 2.5 miles) at 8000 years. Overall, most cases showed a migration distance of 8-11 kilometers (5 - 6.8 miles) at 8000 years.

2.8.2.7 "Evaluation of the Spread of Acid-Gas Plumes Injected in Deep Saline Formations in Western Canada as an Analogue for CO_2 Injection into Continental Sedimentary Basins" (Bachu, et. al., 2005)

For 15 years, acid-gas (H_2S and CO_2) has been injected into deep saline formations at 24 sites in the Alberta Basin in western Canada. The acid-gas is injected at rates ranging from 1.8 metric tons per day to 900 metric tons per day, and at depths ranging from 3200 feet to 9300 feet. The total volume of injected gas was estimated to be between 9000 and 400,000 metric tons at the end of 2003.

The flow of the injected gas is dependent upon the hydrodynamic injection force and conditions, as well as density and viscosity differences between the injected gas and formation water. In order to assess the potential upward leakage of injected gas, the authors of this paper developed a mathematical model to predict the radial spread of an acid gas plume around an injection well. The analytical model showed that plume movement is dependent on formation characteristics such as: permeability, thickness, and porosity. Plume movement is also dependent on injection rate, fluid density and mobility.

The application of the developed model to the 24 injection wells in the Alberta Basin showed that the acid-gas plumes most likely migrated distances ranging from 490 to 6900 feet (1/10th to 1.3 miles) from the injection wells from the time of initial injection to 2003, depending on formation characteristics and volumes injected. The estimates of plume spreads were conducted assuming idealized injection conditions, through vertical, fully penetrating wells into horizontal aquifers of homogeneous characteristics. Also, it was assumed that the injected gas and formation water would not mix, which would produce an overestimation of plume spread. It is important to note that these assumptions do not reflect the natural reality of injection situations.

These distances, although evaluated with a set of simplifying assumptions, provide a good indication of the spread of the plume, and allow for the identification of wells that may potentially serve as leakage paths.

2.8.2.8 "Prediction of Migration of CO_2 Injected Into an Underground Depository: Reservoir Geology and Migration Modeling in the Sleipner Case (North Sea)" (P. Zweigel, et. al., 2000)

CO_2 separated from produced gas has been injected into an underground saline formation in the Sleipner area (North Sea) since 1996. The authors utilized seismic, wireline-log, and sample data as well as the SEMI hydrocarbon migration simulation tool to describe the formation's geology and to make predictions of the final distribution of injected CO_2 (20 MMT) over tens to hundreds of years.

CO_2 is injected near the base of the Miocene-Pliocene Utsira Sands. There are several thin shale horizons within the Utsira Formation that are expected to contain fractures and holes. The sands are highly permeable with porosities ranging from 27 percent to about 40 percent. The Utsira Sands are overlain by the Pliocene Nordland Shales, which are several hundred meters thick and are expected to act as a seal.

The results of the simulation produced two potential final CO_2 distributions: 1. Assuming the top Utsira Sand acts as a long-term barrier the injected CO_2 should migrate in a north-westwards direction reaching a maximum distance of about 12 kilometers (7.5 miles) to the injection site; 2. If the shale layer above the Utsira Sand leaks and CO_2 invades the sand wedge above, migration would occur in primarily a north to north-eastward direction, however a prediction of the maximum migration distance could not be ascertained because the CO_2 would leave the area studied at a point 7 to 10 kilometers (4.3 to 6.2 miles) from the injection site. At the time of this research, preliminary time-lapse surveys indicated that a small fraction of CO_2 may have migrated into the sand wedge.

The modeling revealed that realistic simulation of the fate of CO_2 in such sites required large grid dimensions, very high lateral and vertical seismic resolution, the incorporation of formation heterogeneity, the representation of several temporary and final migration barriers within one model, and the need to run several alternative models.

2.8.2.9 "Reactive Transport Modeling for the Long Term CO_2 Storage at Sleipner, North Sea" (Audigane, et al, 2005)

For this research, the geo-chemical impact of the CO_2 injection on the Sleipner formation is investigated using reactive transport modeling, performed both for the injection phase as well as the long term storage period (several thousand years). The models are initially run in kinetic batch mode in order to determine the principal geo-chemical reactions in the formation due to the presence of CO_2. In a second step, fully coupled reactive transport modeling is performed in order to calculate the evolution of the CO_2 plume in space and time as well as the geo-chemical impact on the formation. The simulations are performed for a period of time of 10,000 years, including 25 years of CO_2 injection. Simulation results predict low chemical activity in the formation with the injected CO_2, according the chosen mineralogy and the initial formation water. The major part of CO_2 is trapped as supercritical gas (structural trapping) and as dissolved gas in the brine (dissolution trapping).

Repeat seismic surveys have shown that the injected supercritical CO_2 moves, due to buoyancy effects, upward from the injection point and accumulates under the overlying caprock and shale layers. A near steady state flow upwards to the top of the formation seems to have been reached by 2001, and most of the CO_2 injected from 2001 to 2002 has spread laterally at the mid and the top level. This recent time-lapse seismic data show no indication of leakage at the Sleipner CO_2 injection site.

The modeling shows that after 25 years of injection, the supercritical CO_2, which is lighter than the brine, reaches the top of the formation and the gas bubble extends laterally up to 500 m away from the injection well, except at the top where the CO_2 accumulates and extends up to 1500 m (approximately 1 mile). The semi-permeable layers induce some accumulation of CO_2 beneath them without stopping the upward migration. Hence, after 100 years, almost all the supercritical CO_2 has reached the top of the formation while dissolving in the brine.

The density of the liquid phase during progressive CO_2 dissolution becomes higher than that of the initial brine and CO_2-loaded brine migrates downward. This density contrast is smaller than that between the supercritical CO_2 and the initial brine, explaining why one can observe that the downward migration of aqueous CO_2 occurs much slower than the upward migration of supercritical CO_2. This mixing of aqueous CO_2 in the liquid phase tends to accelerate the dissolution process and after 5,000 years almost all the supercritical CO_2 has been dissolved, while it is completely dissolved after 10,000 years.

2.8.2.10 "Reactive Geochemical Transport Simulation to Study Mineral Trapping for CO_2 Disposal in Deep Saline Arenaceous Aquifers" (Xu, et al, 2003)

A reactive fluid flow and geochemical transport numerical model for evaluating long-term CO_2 disposal in deep saline formations has been developed. Using this model, the authors performed a number of sensitivity simulations under CO_2 injection conditions for commonly encountered Gulf Coast sediment to analyze the impact of CO_2 immobilization through carbonate precipitation.

A one-dimensional radial model was used. This simplification justification can be derived from the slow rates and long time scales of geochemical changes which will allow processes to be played out that over time will make the distribution of CO_2 more uniform. Initially, injected CO_2 will tend to accumulate and spread out near the top of permeable intervals, partially dissolving in the aqueous phase. CO_2 dissolution causes aqueous-phase density to increase by a few percent; this will give rise to buoyant convection where waters enriched in CO_2 will tend to migrate downward. The process of CO_2 dissolution and subsequent aqueous phase convection will tend to mix aqueous CO_2 in the vertical direction. The time scale for significant convective mixing is likely to be slow (of the order of tens to hundreds of years), and may be roughly comparable to time scales for significant geochemical interactions of CO_2.

The well field was modeled as a 100 meters thick circular region of 8 kilometers (~5 miles) radius and 10 percent porosity, into which CO_2 was injected uniformly at a constant total rate of approximately 3.5 million tons/year (approximately equal to the generation of a 286 MW coal-fired power plant). The CO_2 injection was assumed to occur over a period of 100 years. The fluid flow and geochemical transport simulation was run for a period of 10,000 years. Simulation model results indicate that the CO_2 plume extends out about 6 kilometers (~3.75 miles), for both the 100 and 10,000 year cases, with CO_2 saturations of 40-50 percent occurring in the approximately 50-500 meter distance order of magnitude. CO_2 in the gas phase remains roughly 2-3 times that in the aqueous phase for the first 1,000 years, with the precipitation of a carbonate solid phase beginning to occur after approximately 500-1,000+ years. The simulation was partially validated by field observations of the diagenesis of Gulf Coast sediments, and in particular, sandstones of the Frio formation of Texas. Although the current model does not entirely replicate conditions in the field, the results are generally in agreement.

2.8.2.11 "Modeling of the Long-Term Migration of CO_2 from Weyburn" (Zhou, et al, 2004)

In July 2000, a 4 year research project to study geological sequestration and storage of CO_2 was launched, known as the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project. CO_2 from the North Dakota Gasification plant is transported and injected into an approximately 1450-meter (4750 foot) deep oil formation located in Weyburn, south Saskatchewan, Canada, for enhanced oil recovery. The operator, Encana Resources of Calgary, Alberta, has designed a total of 75 patterns, over approximately 320 acres, for this operation that will last for approximately 34 years.

One of the objectives of this multi-disciplinary project has been to determine the long-term fate of CO_2 injected into the formation. Such a determination involves an evaluation of the potential for CO_2 to migrate to the environment via both natural and man-made (wellbore) pathways. Within a systems analysis of the base scenario of the storage system, CO_2 is expected to migrate via natural (geosphere) and man-made (abandoned wells) pathways under pressure, density, and concentration gradients. Mass partitioning of CO_2 among the three phases accompanies movement of fluids.

The model includes ten formations and six flow barriers from about 100 meters (330 feet) below the Weyburn formation to the ground surface, or about 1800 meters (approximately 6,000 feet) of sedimentary rocks. The lateral extent of the model is approximately 10 kilometers (6 miles) from the EOR boundary, including the formation outside the EOR patterns, as established by previous scoping assessments. The assessment period starts at the end of EOR operation and extends to 5000 years thereafter.

The geosphere migration model considers three phases (oil, gas, and water), and seven components including CO_2 and six pseudo hydrocarbon components. The modified Peng-Robinson equations-of-state are used to dictate fluid phase behavior and component mass partitioning. The migration model uses default CO_2 solubility data, which originate from an empirical relation valid at low pH values and are applicable to most formation conditions. The long-term assessment begins at the end of EOR (in 2034), taking into account the CO_2-in-place, as well as pressure and fluid/component distributions in the field, predicted for the EOR period by independent formation simulation. The caprock is treated as permeable material with non-zero permeability.

Based on the simulation modeling, the CO_2-rich gas phase moves from the bottom to the top of the formation and is trapped under the caprock due to the entry pressure effect and low permeability in the caprock. Oil phase also moves updip accompanied by diffusion of hydrocarbon components (excluding CO_2) from the surrounding formation into the EOR area where much oil has been produced. By diffusion, CO_2 in oil phase moves away from the EOR patterns, which is opposite to the hydrocarbon component movement. Both oil and gas phases inside the 75 patterns, however, are less mobile than the water phase, and are largely confined within, and in the vicinity of, the 75-pattern area. The trapped gas phase forms gas pockets scattered in the 75-pattern area. The gas pockets shrink with time due to loss of CO_2 by dissolution in the moving water. Water movement is driven by pressure gradient during the early depressurization (the process of equilibrium between high EOR residual pressure and the ambient pressure that is in hydrostatic range) period and subsequently is controlled by the ambient flow field after pressure gradient. The CO_2-bearing water that is denser also moves downward. Constant formation water sweeping the 75-pattern area picks up CO_2 from less mobile oil and gas phases, carrying dissolved CO_2 laterally outward and also downward.

Cumulatively, after 5,000 years, the total amount of CO_2 removed from the EOR area is 26.8 percent of the initial CO_2-in-place at the end of EOR (the CO_2 in the 75 patterns at 2034 is 21 MT). Among that, 18.2 percent of the initial CO_2-in-place is released into the geosphere below the formation, 8.6 percent ends up in the formation outside the EOR area, and 0.02 percent goes to the geosphere above. No CO_2 enters any potable aquifer over the 5000-year period. Results from these simulations demonstrate that key parameters affecting CO_2 vertical movement include the caprock permeability and the entry pressure, and indicates the important contribution of the multiple thick barriers above the formation.

The base scenario also defines man-made pathways for CO_2 migration as the existing wells plus those drilled prior to the completion of EOR, all of these abandoned upon completion of EOR. Abandoned wells, although sealed upon abandonment, may provide potential pathways for the injected CO_2 to return to the surface due to degradation of the sealing materials. There are thousands of wells within the study area, the lateral extent of the geosphere migration model. Most of these wells are located outside the 75-pattern area. The geosphere migration results have shown that high CO_2 concentrations in all three phases occur within, and in the vicinity of, the 75 patterns; hence, the focus area for the well leakage assessment is in the center area of the geosphere model that includes the 75 patterns and vicinity. Within the perimeter of this focused area, there are more than 800 existing wells and more are likely to be drilled.

Key assumptions of this modeling approach include: (1) cement seal degradation corresponding to an increase in permeability from 0.001 mD initially to 1 mD at 100 years; (2) no loss of CO_2 to flow inside the formation as well as within the formations surrounding the wellbore; and (3) fast transport of CO_2 once it enters the borehole, i.e., rapid ascent of CO_2 to the surface as gass bubbles. These assumptions result in a conservative assessment, by overestimating CO_2 leakage rates, given the variability and uncertainty of the key parameters used in the model.

With a maximum CO_2 flux modeled through a wellbore of 0.016 kg/day, with an estimated 1,000 wells over the 75-pattern area, yields a total cumulative leakage of CO_2 of ~0.03 MT over 5,000 years. This total amount represents approximately 0.14 percent of the total CO_2-in-place (21 MMT) at the end of EOR. This value is a highly conservative upper estimate, however, as it assumes that the maximum flux is maintained throughout the entire 5,000 year period for all wells. A more representative value is the mean cumulative leakage, corresponding to less than 0.001 percent of the CO_2-in-place at the end of EOR.

These results mean that if the Weyburn CO_2 storage system evolves as expected, the goal of storing greenhouse gas CO_2 can be achieved. Future assessments should focus on alternative scenarios, including seismic activity, open wellbores, and human intrusion.

2.8.3 Fate and Transport – Project Results

2.8.3.1 "Surface Environmental Monitoring at the Frio CO_2 Sequestration Site, Texas" (Nance et al., 2005)

At the Frio Brine Pilot site near Dayton, Texas, surface and near-surface environmental conditions were monitored from the start of CO_2 injection for nine months at the time of reporting. The purpose of the monitoring was to detect CO_2 leaks and associated perfluorocarbon tracers that were injected into the Frio Formation sandstone at a depth of 5,050-ft. Monitoring efforts are on-going and consist of in-field measurements and sampling for laboratory analyses of shallow groundwater and gases that accumulate in water-well headspaces and soils. Shallow Beaumont Formation groundwater hydrochemistry and headspace gases are monitored in four 95-ft wells by field probes, laboratory analyses, and capillary absorption tubes (CATs). Soil gases are collected using hypodermic syringes in four 5-ft deep, sealed dry wells; by CATs placed in 40 0.3 to 1 m deep tubular aluminum installations; and with a portable accumulation chamber, which gases are collected from.

Shallow groundwater pH, electrical conductivity, and alkalinity measurements have varied, however the information is ambiguous with respect to the potential leakage of CO_2 and CH_4. Variability in meteorological conditions may be responsible for the hydrochemical variability.

Because the site is heavily vegetated, temperate and located near marginal wetlands, detection of CO_2 leaks is challenging because of the abundant decaying organic matter. The study concluded that pre-injection baseline data must be developed over time intervals of sufficient length to document the natural cyclic and episodic variations in environmental parameters, in order to accurately discern formation CO_2 leaks.

2.9 LIABILITY ISSUES RELATING TO CARBON SEQUESTRATION

The legal system for addressing liability for a carbon sequestration accident is not mature, there is little case law to draw upon, and legislation to specifically address carbon sequestration liability has not been enacted.

For geologic sequestration, surface leakage and potential risk to human and the near-surface environment is the most important class of risks to be managed, whereas protection of groundwater – the focus of current regulation – is likely to be a substantially less important risk than for current hazardous waste injection. In addition, geologic sequestration raises issues due to large-scale fluid displacement, as well as monitoring and verification that are (arguably) less relevant in the context of more familiar disposal activities (Wilson, et al, 2004).

Because property law in the U.S. is predominantly an issue of state law, there are irregularities between jurisdictions concerning the property interests of geologic CO_2 storage. In particular, there are three key areas of distinction: (1) the distinction between ownership rights needed for injection of CO_2 into a mineral formation and rights needed for injection into a deep saline formation; (2) the distinction between voluntary and involuntary methods of acquisition; and (3) the distinction between ownership of the geologic formation and ownership of the injected CO_2. Although common law concerning natural gas storage will serve as precedent for establishing property interests over CO_2 storage, the issue remains whether federal or state legislation of natural gas storage will govern CO_2 storage (Figueiredo, 2005).

In the gas storage model, the surface owner owns the subsurface storage pore space, while mineral rights owners may have an interest in the residual gas. The gas storage operator retains rights to the stored gas, and must obtain rights to the entire formation. Others cannot produce the gas even if it escapes onto adjacent lands for which rights are not owned. The power of eminent domain is generally available. It is not clear at present if this model would work for CO_2 storage. If so, valuation of the storage rights becomes the key question that must be determined (Van Voorhees, 2006).

EPA's regulatory approach had been based on permit by rule for natural gas storage, based on the "inherent economic incentive" that "reduces the need for scrutiny of these operations"; EPA noted at the time that "the subsurface storage of hydrocarbons is practical only if a preponderant portion of the stored resource can be recovered when desired (44 Fed. Reg., April 20, 1979). The question regarding long-term CO_2 storage is whether the same economic case be made, and do similarly compelling economic incentives (such as credits) apply to containment. The final conclusion will likely be driven by EPA's determination on this issue, with their subsurface injection interpretations having prevailed previously (Van Voorhees, 2006).

The intersection of risk and liability is also an important consideration. Short-term risk might be handled by standard liability, but long-term risk, occurring decades or centuries after the end of the injection phase of the operation will have to be handled in an entirely different manner. Companies do not "live" long enough to make private liability an acceptable policy, especially as even long-lived companies often transfer their outstanding liabilities to smaller companies with shorter life spans. Due to the long sequestration times (most likely hundreds of years), and the relatively short lives of most businesses, it seems clear that some type of transfer of liability to public hands must be made, though how orderly this is and what form it will take could significantly affect private investment in geologic sequestration. How company bond ratings, along with insurance and re-insurance industries are affected by geologic sequestration risk exposure and liability could have an important influence on technological deployment (Wilson, et al, 2004).

An example of one government's response to this issue is in Australia, where the Ministerial Council for Minerals and Petroleum Resources (part of the Commonwealth's Department of Industry, Tourism, and Resources) has issued a draft guiding regulatory framework for regulating geologic sequestration. One element of their framework addresses long term responsibilities. They indicate that, following closure, primary responsibility for the site will lie with the government, although some residual liability may remain with the project proponent. The scope and nature of these residual responsibilities will be resolved upfront, determined and negotiated with the proponent on a project-by-project basis. There may be a need to manage any residual liability that remains with the proponent, for example, through means such as ongoing indemnities, insurance policies, or trust funds (MCMPR, 2004)

As with any industrial project, carbon sequestration has certain risks that are inherent that may lead to liability for damages should an accident or unintended release of CO_2 occur. Standards of liability is a legal concept that establishes the system for resolving claims due to potential liability. Claims for damage could be brought on the basis of negligence, strict liability, implied warranty, or product liability. A claimant could pursue a claim in federal, state, local or even international jurisdiction depending on the nature of the claim.

The consideration of property interests and associated liability is fundamental to carbon capture and sequestration operations. Property interests play a role in determining the cost of geologic storage through the acquisition of necessary geologic formation property rights and the value of storage through ownership of injected CO_2. The determination of property interests will also have implications for long-term liability of any CO_2 emitted to the atmosphere in the future. Liability concerning property rights may derive from several theories, including geophysical surface trespass, geophysical subsurface trespass, or liability from commingling of goods. Geological CO_2 storage faces two potential types of geophysical subsurface trespass: subsurface trespass that results in production or drainage of stored CO_2 from the storage formation, and trespass caused by underground intrusion of injected CO_2 (Figueiredo, 2005)

Legislation on the state or federal level concerning property interests and eminent domain power may provide clarification over property interests and liability of geologic storage of CO_2. Federal or state eminent domain legislation specific to geologic CO_2 storage would be necessary to obtain property rights to the geologic formation by involuntary means. In addition, although property interest and liability for mineral rights have traditionally been addressed by common law, there exists the potential for legislation to define the circumstances of ownership and trespass. Eminent domain legislation and property rights clarification could be done on either the state or the federal level. Federal legislation would be limited to those circumstances where the CO_2 storage is deemed to be within interstate commerce or having a substantial effect on interstate commerce (Figueiredo, 2005).

Claims for damage could be brought on the basis of negligence (failure to execute "reasonable care"); strict liability (imposed for "abnormally dangerous" activities, regardless of reasonable care); implied warranty (fitness for a particular purpose); or product liability (manufacturing/design defects, or failure to warn of possible danger). A claimant could pursue a claim in federal, state, local or even international jurisdiction depending on the nature of the claim.

"During the operational phase of the CO_2 storage project, the responsibility and liability for operational standards, release, and leakage mitigation lies with either the owner of the CO_2, established through contractual or credit arrangements, and/or the operator of the storage facility. Long-term ownership (post-operational phase) will remain with the same entities" (IOGCC, 2005). However, given the nonpermanence of responsible parties over long time frames, oversight of carbon capture and geologic sequestration projects will require creation of specific provisions regarding financial responsibility in the case of insolvency or failure of the licensee. The IOGCC Task Force believes that this assurance ultimately will reside with federal and state governments cooperatively through the establishment of specialized surety bonds, innovative government and privately backed insurance funds, federally guaranteed industry-funded abandonment programs, government trust funds, and public, private, or semi-private partnerships. Following completion of the injection phase, a regulatory framework needs to be established to address long-term monitoring and verification of emplaced CO_2, leak mitigation for the stored CO_2, and determination of long-term liability and responsibility.

A public permitting process must balance competing goals: it should be objective, transparent, and open to public input; also, it should be able to deliver closure in the form of definitive answers over a reasonable period of time. A geologic sequestration protocol should combine performance-based and prescriptive rules. This approach would allow for orderly decision making about specific projects using prescriptive rules, while allowing for public debate about the ability of prescriptive rules to ensure that permitted projects comply with overall performance goals. This type of hybrid system could allow for the integration of new knowledge into the regulatory process and give operators more flexibility in pursuing a performance-based approach for certain programmatic aspects or a prescriptive approach where data is more uncertain (Wilson, et al, 2004).

The oil and gas exploration and production industry has faced liability issues throughout the history of the industry some of which are similar to those associated with the risks of carbon sequestration. Liability will also depend on mineral property rights, which vary from state to state. A firm seeking to store CO_2 in a specific geologic formation would need to know who owns the rights to the formation, and what those specific rights entail. There may be analogous experience in the underground natural gas storage industry, where companies inject and store natural gas in underground formations. The industry has found that entities with potential property rights include the land surface owner, the mineral interest owner, the royalty owner, and the reversionary interest owner (interest in a formation that becomes effective at a specified time in the future). Several types of liability can be considered as described by Figueiredo, et. al. (2005) and summarized here.

The following phases of carbon sequestration have their own different liabilities: Operational, In-situ, and Climate.

- **Operational liabilities** are those associated with the technology of carbon capture, gas processing, gas compression, transport, and injection. Commercial operations have operated successfully with the risks of this segment of sequestration including transportation of CO_2 and EOR in oil fields. Accidents have occurred but have been handled within the current system of laws, regulations, and case law. Operators have recognized the risks and the rewards for each project.
- **In-situ liabilities** are those related to the potential leakage of CO_2 from a subsurface geologic storage facility. The risks of leakage are health impacts, potential fatalities, and unintended carbon releases to the atmosphere. “Once carbon dioxide exits the injection well and enters the geologic formation, its transport and fate are governed by in-situ processes. The choice of appropriate sites is the best way to minimize any adverse effects related to carbon dioxide storage. However, there is a potential for leaks of carbon dioxide from the geologic formation to the surface, migration of carbon dioxide within the formation, and induced seismicity (Heinrich, et. al., 2003). Potential sources of liability include public health impacts, and environmental and ecosystem damage.” (Figueiredo, et al., 2005).
- **Climate liabilities** are those from the secondary impacts of carbon releases and global warming. These liabilities would be much more difficult than the others to assess and litigate.

There are two property interests of significance in determining ownership of the geologic storage formation that has contained oil, gas, or coal. The first is the mineral interest, which comprises the right to explore and remove minerals from the land. The mineral interest may be associated with a royalty interest, which is the right to receive a share of the exploited mineral proceeds. Most states regard a mineral interest as including not only stationary minerals such as coal, but also fugacious minerals, such as oil and gas, unless intent to the contrary is expressed. The second property interest of significance is the surface interest, which consists of all other ownership in the land. In the majority of states in the U.S., the owner of the surface interest owns the geologic formation (Figueiredo,et al 2005).

The determination of property rights over a saline formation is comparable to the mineral formation case. In the majority of states, the owner of the surface interest has the right to make any use of the subsurface space, including the saline formation. Just as in the case of a mineral formation, where ownership of non-depleted minerals must be accounted for, any storage operation needs to take into account ownership of the water contained in the saline formation. Unlike the mineral rights case, however, there are a number of property regimes that states use to determine property rights over the water. In addition , there is an inherent uncertainty concerning the determination of property rights for a saline formation with respect to CO_2 storage because of the lack of case law on point. Instead, the law has focused on property rights over the taking and use of groundwater for consumption (Figueiredo, et al., 2005).

With the onus currently on private industry regarding liability, there may be a need for the federal government to establish legislation to protect the assets of and cap the value of claims brought against companies that would conduct sequestration projects similar to approach taken in the Price-Anderson Act of 1957 (42 U.S.C. § 2210 et seq.). Price Anderson established a framework for payments to the public in case of a nuclear accident. Moreover, assuming the liability for carbon storage is judged low enough, some insurance companies may be willing to bear the risk. Insurance companies will gravitate to situations where risk categories can be pooled, or where the likelihood of accidents can be predicted. The availability of insurance will depend on assessments of the risk of CO_2 leakage from a geologic formation (Figueiredo, et al., 2005).

A “liability cap” may be a double-edged sword for carbon storage. On one hand, it would provide industry with some certainty as to the financial liability associated with any leakage. On the other hand, a liability cap could be detrimental to carbon storage from a public perception standpoint. Liability caps are quite rare and are generally reserved for areas of real catastrophic risk. They are also necessary for situations where no insurance company would be willing to bear the full damages of disaster. For example, in addition to nuclear accidents, Congress has authorized a $100 billion cap on terrorist-related losses by the Terrorism Risk Insurance Act (15 U.S.C. § 6701 et seq.). It is likely that liability caps could stigmatize carbon storage by associating its risks with those of high-level nuclear waste and terrorism (Figueiredo, et. al., 2005).

Another example for liability management is the EPA’s underground injection control (UIC) program. The owners of Class 1 injection wells used for disposing of hazardous waste must demonstrate evidence of financial ability to pay from claims that could stem from the operations. In this situation, the liability remains with the owners and operators of the injection wells. Under the UIC program, permitting and monitoring requirements are implemented to prevent contamination and safeguard potable water sources. However, there still exists the potential for wide-spread harm to human health and the environment. Because of this potential liability, operators of UIC wells for geologic sequestration can minimize their liability through identification of potential migration pathways during the design phase, proper well construction, testing and monitoring of well and seal integrity, and regular and long-term monitoring of injected gases.

Injecting CO_2 into oil and gas formations poses some liability problems because the injection might conceivably interfere with mineral and resource ownership rights. Unitization of oil and gas formations has addressed this concern, but not all fields are unitized. Even in the absence of unitization, claimants have been generally unsuccessful in recovering liability damage claims for water floods. There are no guarantees that CO_2 storage would produce the same liability results if valuable resources are damaged or driven away (Van Voorhees, 2006).

The release of CO_2 from pipelines is also an area of potential liability. Records have been kept by the Office of Pipeline Safety regarding accident history of hazardous liquid pipelines over the last 2 decades. Some leading causes for these accidents are shown in Table 2-43.

Table 2-43. Hazardous Liquid Pipeline, Accident Summary by Cause (2002-2003)

Reported Cause	Number of Accidents	% of Total Accidents	Barrels Lost	Property Damages	% of Total Damages	Fatalities	Injuries
Corrosion	72	26.3	57,160	$18,734,697	24.8	0	0
Materials or Weld Failure	45	16.4	41,947	$30,760,495	40.6	0	0
Equipment Failure	42	15.3	5,717	$2,761,068	3.6	0	0
Excavation	41	15.0	35,220	$9,207,822	12.2	0	0
Other	36	13.1	19,812	$8,918,974	11.8	1	1
Natural Forces	13	4.7	5,045	$2,646,447	3.5	0	0
Operations	13	4.7	8,187	$602,408	0.8	0	4
Other Outside Force	12	4.4	3,068	$2,062,535	2.7	0	0
Total	274	100.0	176,156	$75,694,446	100.0	1	5

Notes:
The failure data breakdown by cause may change as the Office of Pipeline Safety receives supplemental information on accidents.
Sum of numbers in a column may not match given total because of rounding error.

Source: OPS, 2005.

As shown in Table 2-43, most accidents and property damage associated with hazardous liquid pipelines are caused by corrosion or materials/weld failure. The next leading causes of these pipeline accidents are equipment failure and excavation. Although this accident data covers all types of hazardous liquid pipelines, it could be a good indicator of the causes and accident rates for CO_2 pipelines. Subsequently, operators of CO_2 pipelines should be able to avoid many of these accidents, and subsequent liability issues, through adequate corrosion control design, diligent pipeline monitoring, proper maintenance and other prevention strategies.

Between 1995 and November 2005, there have been only 12 CO_2 pipeline accidents reported, one of which carried sour CO_2 (See Table 2-44). In comparison, there were over 960 natural gas pipeline accidents during the same time period. Although there frequency of CO_2 pipeline accidents is rare, this can be attributed to the relatively few miles of CO_2 pipeline currently in the U.S. Using natural gas pipeline accident data as a benchmark for comparison, over the last 10 years natural gas pipeline accidents averaged $484,000 in property damages per incident, whereas CO_2 pipeline accidents resulted in less than $1/10^{th}$ this property damage, at an average of $42,000 per incident (OPS, 2005). For this same reporting period, natural gas pipeline accidents resulted in 82 injuries and 29 fatalities, whereas the CO_2 pipeline accidents resulted in no injuries or fatalities. Table 2-45 lists CO_2 pipeline accident statistics through November 2006.

Table 2-44. CO_2 Pipeline Accident History Compared with Natural Gas Pipelines

Type of Pipeline	Number of Accidents (1995 – Nov 2005)	Property Damage	Number of Fatalities	Number of Injuries
CO_2	12	$505,292	0	0
sour CO_2	1	$3,360	0	0
natural gas	967	$467,925,347	29	82

Table 2-45. CO_2 Pipeline Accident History, 1990 - 2006

Year	No. of Accidents	Barrels Lost	Property Damages	Fatalities	Injuries
2006b (1% H_2S)	1	100	$0	0	0
2006a	1	307	$559	0	0
2005	1	2,394	$3,880	0	0
2004	2	8,180	$73,430	0	0
2003	none				
2002	2	3,912	$10,430	0	0
2001	1	18	$11,052	0	0
2000	1	83	$371,000	0	0
1999	none				
1998	none				
1997	1	1,159	$2,000	0	0
1996	3	4,499	$33,000	0	0
1995	1	0	$500	0	0
1994	3	6	$51,696	0	0
1993	none				
1992	none				
1991	none				
1990	none				

Source: OPS, 2007.

For the DOE sequestration program, the government would probably have little liability should a sequestration funded project result in a claim. This is because the federal government is protected through the principle of sovereign immunity so that states and individuals can litigate against the federal government only if the government allows the case to proceed. This implies that the companies or institutions that would perform a sequestration project using DOE funding would not be indemnified by the federal government.

Consideration of long-term liability is a key element in assessing the viability of geologic carbon storage. The way in which liability is addressed may have a significant impact on costs and indirectly on public perceptions of geologic storage. Liability itself is not a new topic; indeed, operational liability of CO_2 injection is handled routinely in the oil and gas industries as a part of doing business. Whether liability for geologic carbon storage will be treated like the historic treatment of natural gas which has imposed relatively low costs on operators, or more like hazardous waste which has been much more burdensome to participants (and much more politicized) is uncertain (Figueiredo, et al, 2005). Other major outstanding legal issues include short-term measurement, monitoring, and verification; long-term monitoring and management; long-term liability for operation and leakage; and remediation methods and responsibility (Van Voorhees, 2006).

3.0 ENVIRONMENTAL BASELINE INFORMATION

3.1 INTRODUCTION

This chapter provides environmental baseline information for different regions and individual states within the U.S. that could potentially host carbon sequestration projects. The following aspects will be discussed in this chapter: atmospheric resources, geologic resources, surface water resources, biological resources, cultural resources, aesthetic and scenic resources, land use, materials and waste management, health and safety, socioeconomics and infrastructure.

3.2 ATMOSPHERIC RESOURCES

The following section describes baseline air quality with respect to the states within the Regional Partnerships and U.S. climate.

3.2.1 National Context

Atmosphere is defined as the mixture of gases surrounding any celestial object that has a gravitational field strong enough to prevent the gases from escaping, especially the gaseous envelope of Earth (Encarta, 2005a). Earth's atmosphere is comprised of nitrogen (N_2) (78 percent) and oxygen (O_2) (21 percent) with the remaining 1 percent comprised of argon (0.9 percent), CO_2 (0.03 percent), varying amounts of water vapor, and trace amounts of hydrogen (H_2), ozone, methane (CH_4), carbon monoxide (CO), helium, neon, krypton, and xenon (Encarta, 2005a).

The Earth's atmosphere is divided into several layers. The lowest region, the troposphere, extends from the Earth's surface up to about 6 miles (10 kilometers) in altitude. Virtually all human activities occur in the troposphere. The next layer, the stratosphere, continues from 6 to 30 miles above the surface (10 km to about 50 km). Most commercial airline traffic occurs in the lower part of the stratosphere. In the stratosphere, the chemical compound ozone plays a vital role in absorbing harmful ultraviolet radiation from the sun.

The Earth naturally absorbs and reflects incoming solar radiation and emits longer wavelength terrestrial (thermal) radiation back into space. On average, the absorbed solar radiation is balanced by the outgoing terrestrial radiation emitted to space. A portion of this terrestrial radiation, though, is itself absorbed by gases in the atmosphere. The energy from this absorbed terrestrial radiation warms the Earth's surface and atmosphere, creating what is known as the "natural greenhouse effect" (Figure 1-1). Without the natural heat-trapping properties of these atmospheric gases, the average surface temperature of the Earth would be about 91°F lower (EPA, 2002a).

Natural processes such as solar-irradiance variations, variations in the Earth's orbital parameters and volcanic activity can produce variations in climate. The climate system can also be influenced by changes in the concentration of various gases in the atmosphere, which affect the Earth's absorption of radiation.

3.2.1.1 Global Warming and Greenhouse Gases

Since the beginning of the Industrial Revolution, humans have been burning fossil fuels and conducting other activities, such as clearing land for agriculture or urban settlements, which release some of the same gases that trap heat in the atmosphere, including CO_2, CH_4, and N_2O. As these gases build up in the atmosphere, they trap more heat near the Earth's surface, causing Earth's climate to become warmer than it would naturally (Encarta, 2005b).

Although the Earth's atmosphere consists mainly of O_2 and N_2 neither play a significant role in promoting the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, CO_2, and other trace gases in the atmosphere that absorb terrestrial radiation leaving the surface of the earth (EPA, 2002a).

Naturally occurring GHGs include water vapor, CO_2, CH_4, N_2O, and O_3. Other halogenated substances are also GHGs but are primarily the products of industrial activities. Because CFCs, HCFCs and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer, these gases are not included in national GHG inventories. There are several other gases that can affect the absorptive characteristics of the atmosphere. These tropospheric gases, referred to as ambient air pollutants, include: CO, nitrogen dioxide (NO_2), SO_2 and tropospheric (ground level) O_3.

CO_2, CH_4, and N_2O are continuously emitted to and removed from the atmosphere by natural processes on Earth. However, anthropogenic activities can cause additional quantities of these and other GHGs to be emitted or sequestered, changing their global average atmospheric concentrations.

A description of each GHG, its sources, and role in the atmosphere is provided below (EPA, 2002a).

> CO_2 has an atmospheric lifetime between 50 and 200 years.

- **Water Vapor (H_2O):** Water vapor is the most abundant and dominant GHG in the atmosphere. Human activities are not believed to directly affect the average global concentration of water vapor; however, the radiative forcing (change in the balance between radiation coming into the atmosphere and radiation going out) produced by increased concentrations of other GHGs may indirectly affect the hydrologic cycle. A warmer atmosphere has an increased water-holding capacity. However, increased concentrations of water vapor affect the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Earth has an average albedo of 37 to 39 percent, which means that on average the Earth's surface, including the atmosphere and cloud cover, reflects these percentages of light radiation back into space.

- **Carbon Dioxide (CO_2):** In nature, carbon is cycled between various atmospheric, oceanic, terrestrial biotic, aquatic biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and oceans and, to a lesser extent, between the atmosphere and terrestrial biota. In the atmosphere, carbon predominantly exists in the oxidized form of CO_2, which has increased from approximately 280 ppm by volume in pre-industrial times to 367 ppm by volume in 1999, a 31 percent increase. CO_2 has an atmospheric lifetime between 50 and 200 years.

- **Methane (CH_4):** CH_4 is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal wastes. Methane is also emitted during the production and distribution of natural gas and petroleum and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH_4 have increased by about 150 percent since pre-industrial times, although the rate of increase has been declining. CH_4 is removed from the atmosphere by reacting with the hydroxyl radical (OH) and is ultimately converted to CO_2. Increasing emissions of CH_4 reduce the concentration of OH, a feedback that may increase CH_4's atmospheric lifetime (EPA, 2002a). CH_4, which has 21 times the 100-year GWP of CO_2, has an atmospheric lifetime between 9 and 15 years.

- **Nitrous Oxide (N_2O):** Anthropogenic sources of N_2O emissions include agricultural soils, especially the use of synthetic and manure fertilizers, fossil fuel combustion (especially from mobile sources), nylon and nitric acid production, wastewater treatment, waste combustion and biomass burning. The atmospheric concentration of N_2O has increased 16 percent since 1750. N_2O is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere. Nitrous oxide has an atmospheric lifetime of approximately 120 years and has 310 times the 100-year GWP of CO_2.

- **Ozone (O_3):** Ozone is present in both the upper stratosphere and at lower concentrations in the troposphere (where it is the main component of smog). During the last two decades, CFCs and halons have depleted stratospheric O_3 concentrations and resulted in a change of the Earth's radiative energy. This change in the net radiative energy, or solar radiation energy, that enters and exits the atmosphere is termed a radiative forcing. The loss of O_3 in the stratosphere has resulted in negative radiative forcing. The depletion of the O_3 layer and radiative forcing was expected to reach a maximum around 2000 before starting to recover. The past increase in tropospheric O_3 is estimated to provide the third largest increase in radiative forcing since the pre-industrial era, after CO_2 and CH_4. Tropospheric O_3 is produced from the reactions of VOCs and NOx in the presence of sunlight.
- **Carbon Monoxide (CO):** Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric O_3 through chemical reactions with other atmospheric constituents that would otherwise assist in destroying these gases. CO is created when carbon-containing fuels are burned incompletely. Through natural processes, CO is eventually oxidized to become CO_2. Carbon monoxide concentrations are both short-lived and spatially variable.
- **Nitrogen Oxides (NO_x):** Nitrogen oxides are created by lightning, soil microbial activity, biomass burning, fuel combustion and in the stratosphere, the photo-degradation of N_2O. NO_x is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying degrees, NO_2 is the most common pollutant. The climate change effects of NO_x are indirect and the result of their promotion of formation of O_3 in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects. Concentrations of NO_x are both relatively short-lived and spatially variable.

As stated in Chapter 1, strong evidence is emerging that GHG emissions are linked to potential climate-change impacts. Concentrations of CO_2 in the atmosphere have increased rapidly in recent decades, and the increase correlates with the rate of world industrialization. In the last 100 years, atmospheric CO_2 concentrations have increased from approximately 280 ppm to nearly 380 ppm.

> The IPCC concluded that the warming in the northern hemisphere in the 20th century is probably greater than any warming that has occurred during the past 1,000 years.

The IPCC concluded in 2001 that the warming of the northern hemisphere in the 20th century is probably greater than any warming that has occurred during the past 1,000 years and that most of the warming during the past 50 years is attributable to anthropogenic (human-caused) emissions of GHGs (EPA, 2004c). Graphics on the IPCC website (http://www.ipcc.ch/present/graphics/2001syr/large/05.16.jpg) depict temperature changes in the Northern Hemisphere over the last 1000 years. Greenhouse gases leave a distinctive "fingerprint" on climate, affecting temperature and precipitation in patterns that differ from those caused by fluctuations in solar output or natural variability (EPA, 2004c). As noted in Chapter 1 today's atmosphere contains 33 percent more GHGs than it did prior to the Industrial Revolution, and the concentration is increasing steadily at a rate of more than 1 ppm per year. It is generally recognized that anthropogenic GHG emissions are having a significant effect on global climate and that GHG emissions will need o be controlled to avoid future adverse climate impacts.

3.2.1.2 Climate

The Earth's climate has undergone many natural changes in the past, and it will continue to change naturally in the future. Today, however, there is another factor to consider. During the past century, people have burned millions of tons of fossil fuels to produce energy, releasing large quantities of GHGs and other substances that affect the climate (EPA, 2004a).

The U.S. is known for its diverse climates, which can be broken down into different climatic regions. The predominant climatic regions in the U.S. consist of Humid Continental – Warm Summer, Humid

Continental – Hot Summer, Humid Subtropical, Mediterranean, Marine West Coast, Semiarid, Desert, Subarctic, and Tundra, which are described below (Encarta, 2005d). Figure 3-1 represents the different climate regions across the U.S. and Alaska.

3.2.1.2.1 Humid Continental Climates

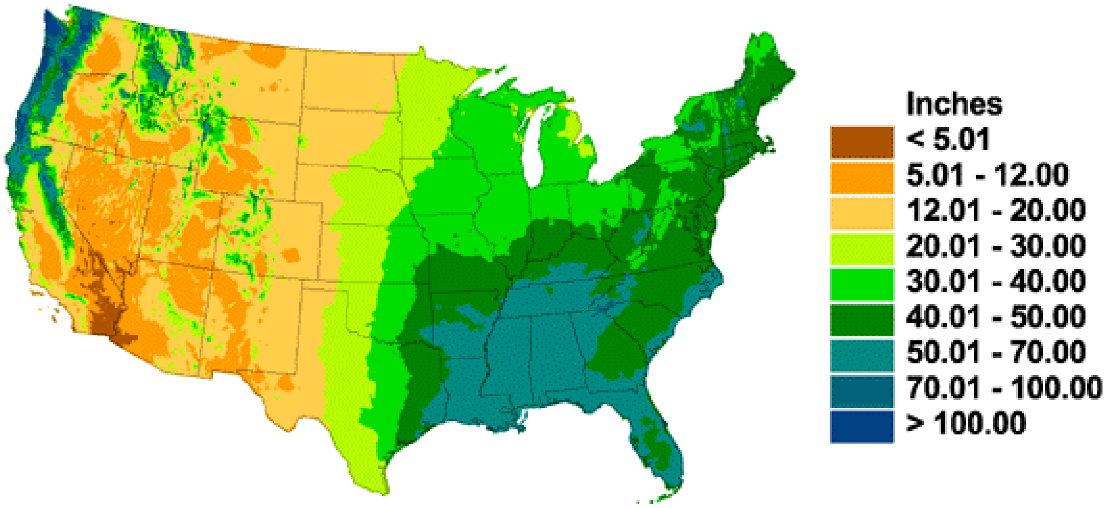
The eastern part of the U.S. is comprised of the Humid Continental and Humid Subtropical climate types. Humid Continental climate has two subtypes: those areas with hot summers and those with warm summers. The Humid Continental climates are transitional climates between the severe Subarctic climate region in Canada and the warmer Humid Subtropical region of the southern and southeastern U.S. These climates are mixing zones between cold polar air masses surging southward and tropical air moving northward.

3.2.1.2.2 Humid Continental (Hot Summer)

This subregion extends from the East Coast deep into the continental interior, south of the Great Lakes and is located between 35 and 45 degrees north latitude, it includes Rhode Island, Connecticut, Massachusetts, and southern New York, as well as New Jersey, Delaware, Maryland, Pennsylvania, West Virginia, Ohio, Indiana, Illinois, southern Wisconsin, and southern Michigan. In this climate zone, winters are cold and summers are hot. January temperatures usually average below 0°C (32°F), while July temperatures average between 18°C (65°F) and 24°C (75°F). Summers are humid with thunderstorms that may produce hail or tornadoes and annual precipitation averages from between 20 and 40 inches. Refer to Figure 3-2 for a map of the annual average precipitation for the U.S.

Source: USDA Forest Service, 2007.

Figure 3-1. United States Climate Regions



Source: NCDC, 2007

Figure 3-2. United States Annual Average Precipitation Map

3.2.1.2.3 Humid Continental (Warm Summer)

The "warm summer" subregion falls roughly from 45 degrees to 60 degrees north latitude and it lies astride the U.S.-Canadian border and includes most of the Great Lakes region. States in this climate region are Maine, New Hampshire, Vermont, upper New York, upper Michigan, northern Wisconsin, and Minnesota, as well as North Dakota, part of South Dakota, Montana, and sections of surrounding states. Winters in this area are harsh; snow remains on the ground for periods of up to five months. January average temperatures are less than -15°C (5°F) and summers are pleasantly cool, but short, with average monthly temperatures ranging from 18°C to 20°C (64°F to 68°F). Annual precipitation averages 32 inches. In the summer, precipitation is high when thunderstorms form along moving cold fronts and squall lines. Much of the winter precipitation is snow, which can remain on the ground for a couple of months at a time. The western area of prairie is a bit drier than the east.

3.2.1.2.4 Humid Subtropical

This climate region, characterized by long, hot, sultry summers, is found in the southeastern U.S. North Carolina, South Carolina, Georgia, Alabama, Mississippi, Louisiana, Florida, and portions of surrounding states are included in this climatic region. Temperatures average 26°C (80°F) in the summer and range from 4°C to 10°C (40°F to 50°F) in the winter. The Humid Subtropical climate receives ample precipitation, averaging about 30 inches annually in the western part of the region to more than 60 inches per year in the southern part. Most precipitation occurs in the summer months as rainfall. A polar air mass can push southward and bring an infrequent snowstorm, but snow seldom stays on the ground for more than a few days.

3.2.1.2.5 Semiarid

The Semiarid climates are found in sections of the Great Plains regions, parts of Texas, New Mexico, the intermontane basin of Nevada, parts of eastern Washington and Oregon, and sections of neighboring states. The temperature range is extreme. During winter the temperature can drop as low as -1°C (30°F) and summer temperatures often are in the upper 30°s C (lower 100°s F). Temperatures are considerably higher in Las Vegas, Nevada, located at the southern end of the region with the average July temperature being 32°C (90°F) and the average high temperature in January being in the lower 10°s C (lower 50°s F).

Annual rainfall is from 10 to 20 inches, which is enough to support grasses but not enough to maintain a forest cover.

3.2.1.2.6 Desert

The Desert climate region is found in the Southwest and includes southern inland California, Arizona, New Mexico, and parts of Nevada and Texas. The area receives less than 10 inches of rainfall annually and high temperatures cause any moisture to evaporate rapidly. Desert climates can be typically found on the dry side of mountain ranges. Mountains create a rain-shadow effect, with a belt of arid climate to the leeward side (the side opposite the prevailing winds) of the mountain barrier. Temperatures during the hottest months average from 29°C to 35°C (from 85°F to 95°F), and the midday readings of 40°C to 43°C (105°F to 110°F) are common (Encarta, 2005d). The winter daily maximum usually averages 18°C to 24°C (65°F to 75°F). Winter nights are chilly, averaging 7°C to 13°C (45°F to 55°F).

3.2.1.2.7 Mediterranean Climate

The Mediterranean climate of central and coastal California is characterized by dry summers and mild, rainy winters. Summer temperatures range from 20° to 25°C (68° to 77°F), and winter temperatures are a mild 4° to 10°C (40° to 50°F). The average precipitation of 360 millimeters (mm) to 640 mm (14 in to 26 in) per year occurs during the cool winter season and contrasts sharply to the area's dry summer months.

3.2.1.2.8 Marine West Coast

The Marine West Coast climate extends from northern California through the coastal sections of Oregon, Washington, and southern Alaska. Mild winters and summers distinguish this climate, even though inland climates at the same latitude have bitter winters and hot summers. In the Marine West Coast region, summer temperature averages range from 15°C to 20°C (from 59°F to 68°F), and the coldest months have a temperature range of 4°C to 10°C (40°F to 50°F). Winds out of the west bring in the moist air from the Pacific Ocean. Moist air rises over the mountainous Marine West Coast and releases its moisture. The result is high annual precipitation with extensive cloud development and profuse rainfall. The annual total rainfall may be as much as 57 inches, most of which falls during the winter months.

3.2.1.2.9 Subarctic

The Subarctic climate is found in most of interior Alaska, reaching as far north as the Arctic Circle (60° north latitude), where it gives way to a Tundra climate zone. Summer is very short in the climate region with temperatures averaging about 10°C (50°F) and winter starts as early as October with average temperatures of less than -15°C (5°F) for at least three or four months. Precipitation is usually less than 20 inches annually, and most falls as rain during the brief summer. Snow may accumulate to depths of 1 foot or more. Permanently frozen soil known as permafrost exists in the Subarctic climate. Permafrost requires that buildings be constructed to prevent heat losses because escaping heat can melt adjacent frozen subsoils, causing construction projects to slowly sink into saturated soils.

3.2.1.2.10 Tundra

The Tundra climate extends north of the Arctic Circle, from the Subarctic region to the Arctic Ocean. Like the Subarctic region, the Tundra experiences extremely long periods of daylight in the summer and extended periods of darkness during winter months. The average temperature for July, the warmest month, never exceeds 10°C (50°F). Annual precipitation is less than 14 inches, and much of the precipitation falls during the warm season in the form of rain or occasional wet snows. The meager winter snowfall is usually dry and powdery.

3.2.1.3 National Ambient Air Quality Standards

Air pollution is caused by a variety of sources. Industrial operations, cars and other modes of transportation, and natural sources such as volcanic eruptions and wildfires can emit a wide variety of pollutants. The U.S. EPA has established National Ambient Air Quality Standards (NAAQS) for 6 principal air pollutants (also called the criteria pollutants): NO_2, O_3, SO_2, particulate matter, CO, and lead (Pb). Table 3-1 provides estimates of major pollutant emissions from 1970 to 2003. Table 3-2 depicts the NAAQS.

Table 3-1. National Air Pollutant Emissions Estimates for Major Pollutants

	Millions of Tons Per Year								
	1970	**1975**	**1980**	**1985**	**1990**	**1995**	**20001**	**2002**	**2003[2]**
Carbon Monoxide (CO)	197.3	184.0	177.8	169.6	143.6	120.0	201.4	96.4	93.7
Nitrogen Oxides (NOx)[3]	26.9	26.4	27.1	25.8	25.1	24.7	22.3	20.8	20.5
Particulate Matter4 (PM-10)	12.2	7.0	6.2	3.6	3.2	3.1	2.3	2.4	2.3
Particulate Matter (PM2.5) [5]	NA	NA	NA	NA	2.3	2.2	1.8	1.8	1.8
Sulfur Dioxide (SO_2)	31.2	28.0	25.9	23.3	23.1	18.6	16.3	15.3	15.8
Volatile Organic Compounds (VOC)	33.7	30.2	30.1	26.9	23.1	21.6	16.9	15.8	15.4
Lead[6]	0.221	0.16	0.074	0.022	0.005	0.004	0.003	0.003	0.003
Totals[7]	301.5	275.8	267.2	249.2	218.1	188.0	160.2	150.2	147.7

Note: Fires and dusts excluded
1 In 1985 and 1996 EPA refined its methods for estimating emissions. Between 1970 and 1975, EPA revised its methods for estimating particulate matter emissions.
2 The estimates for 2003 are preliminary.
3 NOx estimates prior to 1990 include emissions from fires. Fires would represent a small percentage of the NOx emissions.
4 PM estimates do not include condensable PM, or the majority of PM-2.5 that is formed in the atmosphere from 'precursor' gases such as SO2 and NOx.
5 EPA has not estimated PM-2.5 emissions prior to 1990.
6 The 1999 estimate for lead is used to represent 2000 and 2003 because lead estimates do not exist for these years.
7 PM-2.5 emissions are not added when calculating the total because they are included in the PM-10 estimate.

Source: EPA, 2003.

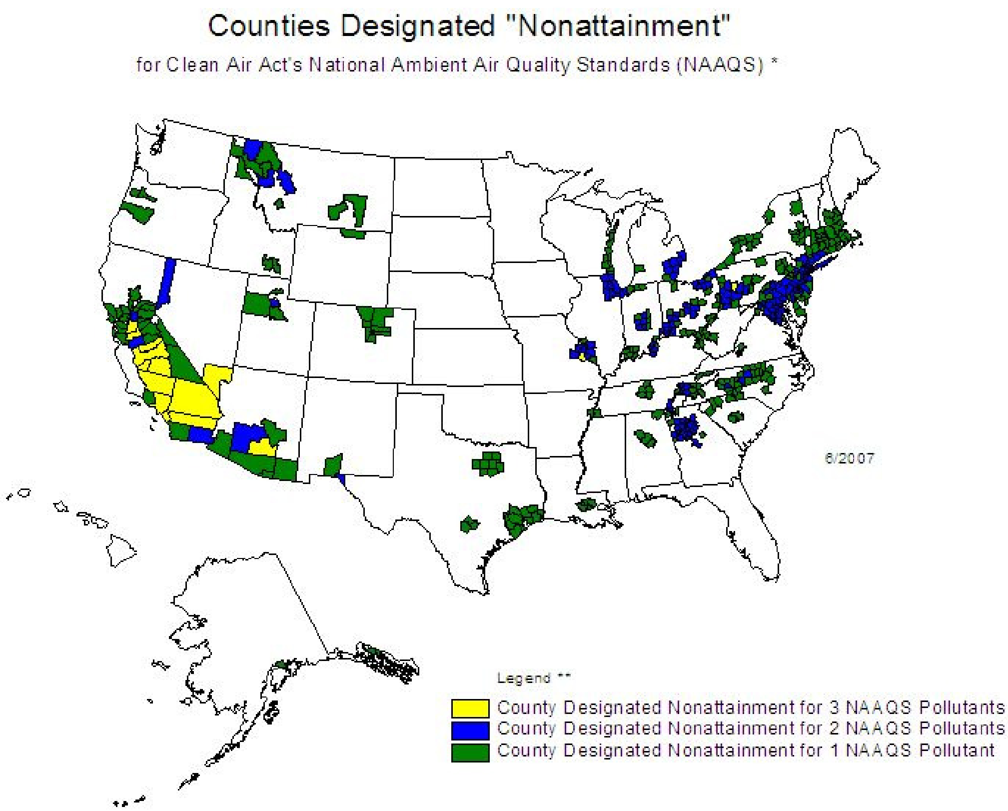
Table 3-2. National Ambient Air Quality Standards

Pollutant	Primary Standards	Averaging Times	Secondary Standards
Carbon Monoxide (CO)	9 ppm (10 mg/m)	8-hour	None
	35 ppm (40 mg/m)	1-hour	None
Lead (Pb)	1.5 µg/m	Quarterly Average	Same as Primary
Nitrogen Dioxide (NO_2)	0.053 ppm (100 µg/m)	Annual (Arithmetic Mean)	Same as Primary
Particulate Matter (PM-10)	50 µg/m	Annual (Arith. Mean)	Same as Primary
	150 µg/m	24-hour	
Particulate Matter (PM-2.5)	15.0 µg/m	Annual (Arith. Mean)	Same as Primary
	65 µg/m	24-hour	
Ozone (O_3)	0.08 ppm	8-hour	Same as Primary
	0.12 ppm	1-hour	Same as Primary
Sulfur Oxides (SO_x)	0.03 ppm	Annual (Arith. Mean)	-------
	0.14 ppm	24-hour	-------
	-------	3-hour	0.5 ppm (1,300 µg/m)

Source: EPA, 2004b.

3.2.1.3.1 EPA Designations

The EPA has designated geographical regions known as nonattainment areas when an area does not meet the air quality standard for one of the criteria pollutants. The area may be subject to the formal rulemaking process that designates the area as nonattainment. The 1990 Clean Air Act Amendments further classify O_3, CO, and some particulate matter nonattainment areas based on the magnitude of an area's problem (EPA, 2004b). Nonattainment classifications may be used to specify what air pollution reduction measures an area must adopt and when the area must reach attainment. Figure 3-3 depicts nonattainment status for different counties in the U.S.



Source: EPA, 2007.

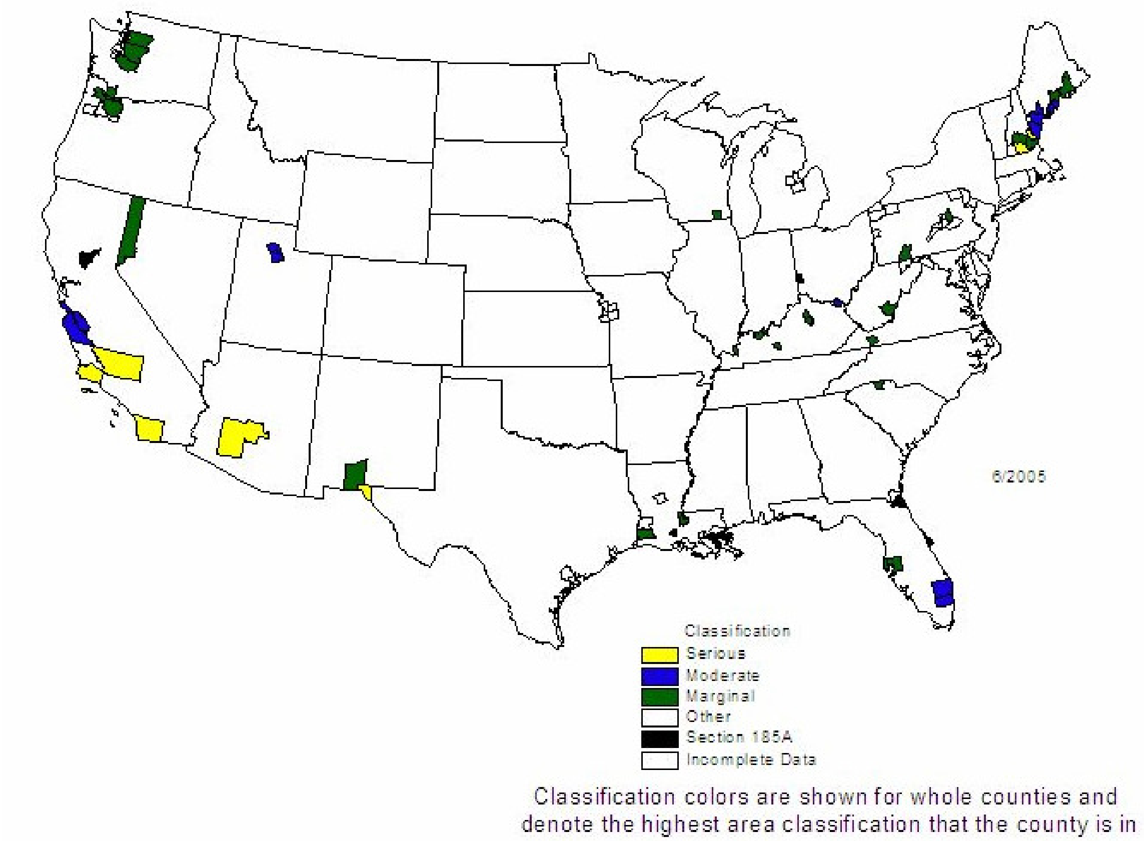
Figure 3-3. Counties Designated Nonattainment in the United States

3.2.1.3.2 Nitrogen Dioxide (NO_2)

NO_2 is a reddish brown, highly reactive gas that is formed in the ambient air through the oxidation of NO. Nitrogen oxides (NO_x), play a major role in the formation of O_3, PM, haze, and acid rain (EPA, 2004b). While EPA tracks national emissions of NO_x, the national monitoring network measures ambient concentrations of NO_2 for comparison to national air quality standards (EPA, 2002b). The major sources of man-made NO_x emissions are high-temperature combustion processes such as those that occur in automobiles and power plants (EPA, 2002b). There are no areas designated as nonattainment for NO_2.

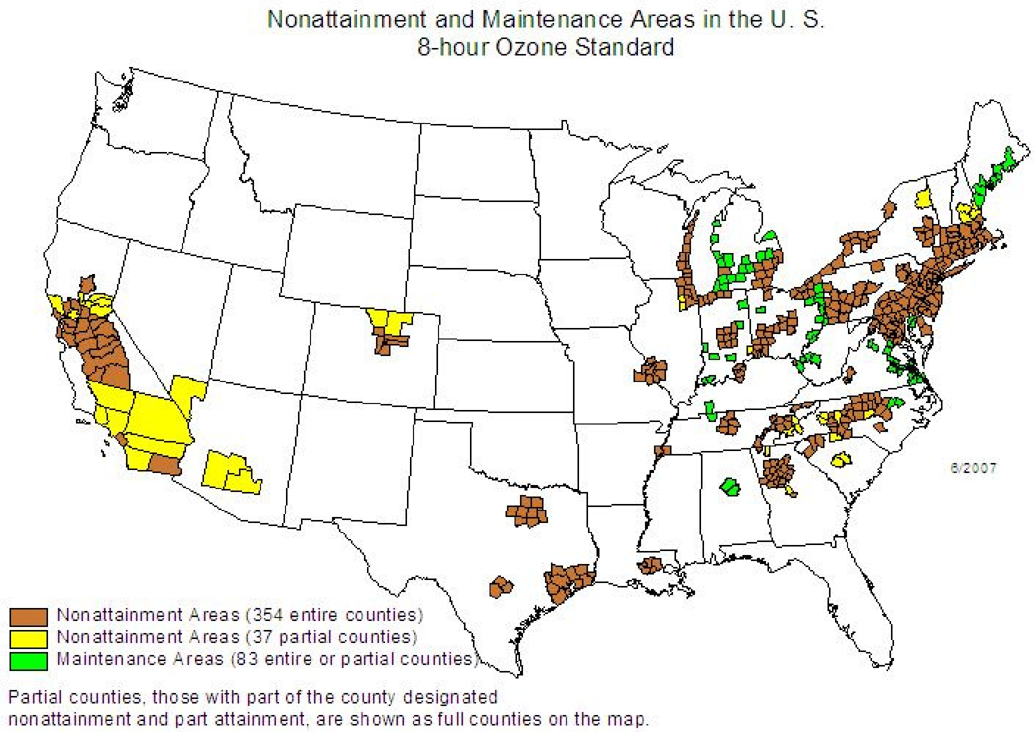
3.2.1.3.3 Ozone (O_3)

The pollutants that contribute to O_3 formation are NO_x and VOCs (EPA, 2002b). Some of the major sources of these pollutants are vehicle and engine exhaust, emissions from industrial facilities, combustion from electric utilities, gasoline vapors, chemical solvents, and biogenic emissions from natural sources (EPA, 2002b). Many urban areas tend to have higher levels of O_3, but even rural areas with relatively low amounts of local emissions may experience high O_3 levels because the wind transports O_3 and the pollutants that form it hundreds of miles away from their original sources (EPA, 2002b). Figure 3-4 and Figure 3-5 portray the 1-hour O_3 and 8-hour O_3 nonattainment status for counties in the U.S., respectively.



Source: EPA, 2004c.

Figure 3-4. One-Hour Ozone Nonattainment Areas in the United States

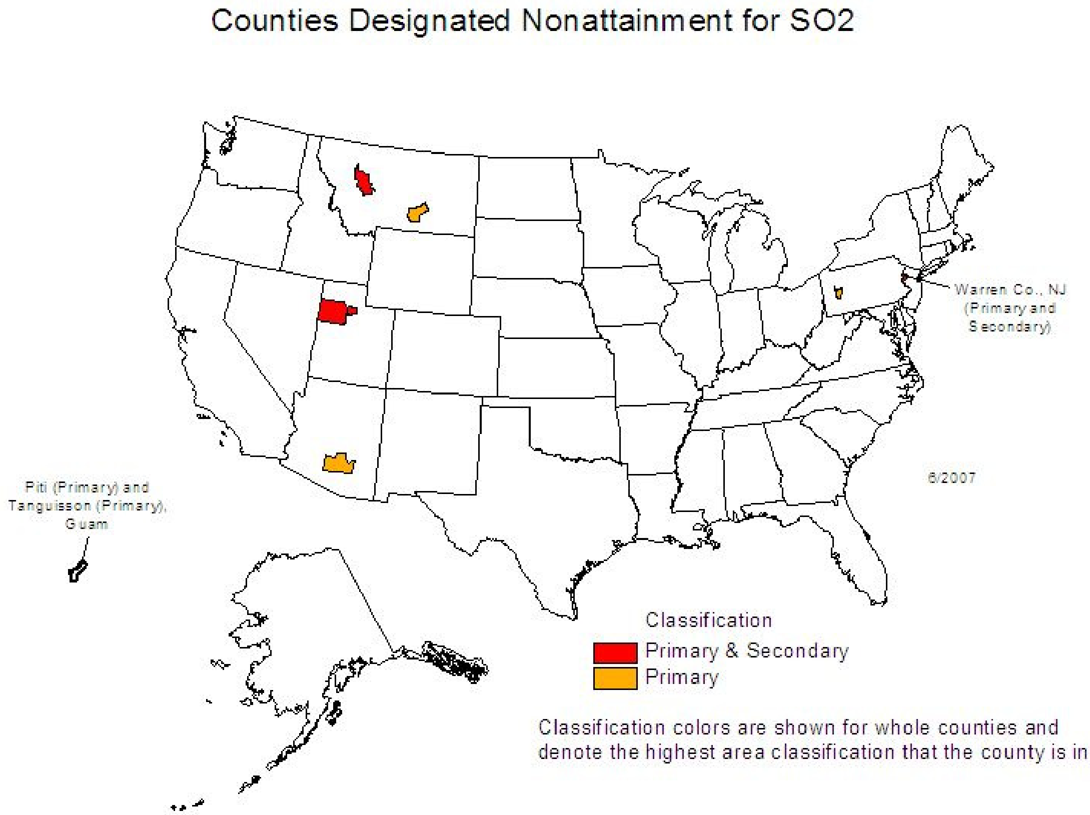


Source: EPA, 2007.

Figure 3-5. Eight-Hour Ozone Attainment and Nonattainment Areas in the United States

3.2.1.3.4 Sulfur Dioxide (SO_2)

SO_2 belongs to the family of SO_x gases. These gases are formed when fuel containing sulfur (primarily coal and oil) is burned at power plants and during metal smelting and other industrial processes (EPA, 2002b). Most SO_2 monitoring stations are located in urban areas with the highest monitored concentrations of SO_2 being recorded near large industrial facilities (EPA, 2002b). Fuel combustion, largely from electricity generation, accounts for most of the total SO_2 emissions. Figure 3-6 portrays areas designated nonattainment for SO_2.

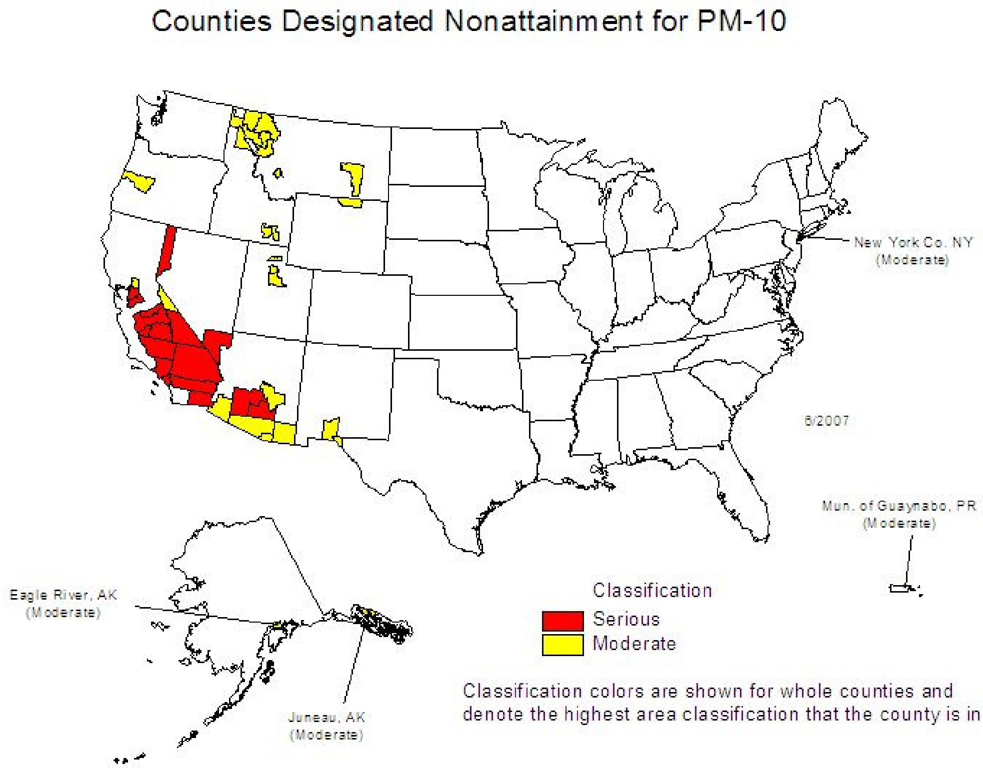


Source: EPA, 2007.

Figure 3-6. Counties Designated Nonattainment for Sulfur Dioxide in the United States

3.2.1.3.5 Particulate Matter (PM)

Particulate Matter is a mixture of solid particles and liquid droplets found in the air. Some particles are large enough to be seen as dust or dirt and others are so small they can be detected only with an electron microscope (EPA, 2002b). PM-2.5 describes the “fine” particles that are less than or equal to 2.5 micrometers (µm) in diameter. PM-10 refers to all particles less than or equal to 10 µm in diameter (about one-seventh the diameter of a human hair) (EPA, 2002b). "Primary" particles, such as dust from roads or black carbon (soot) from combustion sources, are emitted directly into the atmosphere and "secondary" particles are formed in the atmosphere from primary gaseous emissions. Examples include sulfates formed from SO_2 emissions from power plants and industrial facilities; nitrates formed from NO_x emissions from power plants, automobiles, and other combustion sources; and carbon formed from organic gas emissions from automobiles and industrial facilities (EPA, 2002b). Figure 3-7 shows counties designated nonattainment for particulate matter (PM-10).

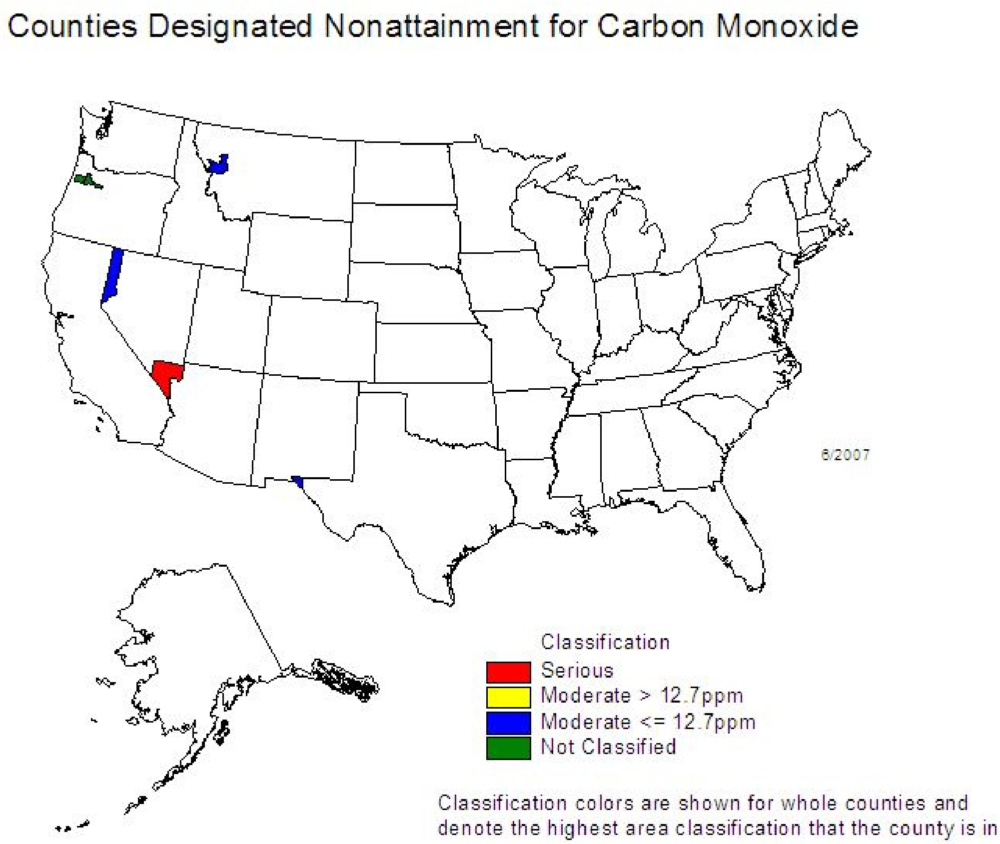


Source: EPA, 2007.

Figure 3-7. Counties Designated Nonattainment for Particulate Matter in the United States

3.2.1.3.6 Carbon Monoxide (CO)

CO is a colorless and odorless gas that is formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 60 percent of all CO emissions nationwide (EPA, 2002b). High concentrations of CO generally occur in densely populated areas with heavy traffic congestion. In cities, as much as 95 percent of all CO emissions may come from automobile exhaust (EPA, 2002b). Other sources of CO emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires (EPA, 2002b). Peak CO concentrations typically occur during the colder months of the year when CO automotive emissions are greater and nighttime inversion conditions (where air pollutants are trapped near the ground beneath a layer of warm air) are more frequent (EPA, 2002b). Figure 3-8 presents the counties within the U.S. that have nonattainment status for CO. The map shows serious CO emission problems in southern California and surrounding areas due in part to the wildfires in the southwestern states during 2003.



Source: EPA, 2007.

Figure 3-8. Counties Designated Nonattainment for Carbon Monoxide in the United States

3.2.1.3.7 Lead (Pb)

In the past, automotive sources were the major contributor of Pb emissions to the atmosphere. As a result of EPA's regulatory efforts to reduce the content of Pb in gasoline; however, the contribution of air emissions of Pb from the transportation sector, and particularly the automotive sector, has greatly declined over the past two decades (EPA, 2002b). Today, industrial processes, primarily metals processing, are the major source of Pb emissions to the atmosphere with the highest air concentrations of Pb usually being found in the vicinity of smelters and battery manufacturers (EPA, 2002b). Figure 3-9 presents counties designated nonattainment for Pb.

Source: EPA, 2007.

Figure 3-9. Counties Designated Nonattainment for Lead in the United States

3.2.1.4 State GHG Registries

EPA's State and Local Capacity Building Branch partners with states to develop GHG inventories and action plans. Forty-one states and Puerto Rico have completed inventories (See Figure A-1 in Appendix A). Each inventory identifies the major sources of GHG emissions and creates a baseline upon which reduction strategies are based. States play a critical role in reducing GHG emissions; many states have developed state action plans that draw heavily on the information in their inventories.

The inventories present annual emissions of GHG by sector (e.g., energy, agriculture, waste), by source (e.g., transportation emissions, manure management), and by gas (e.g., CO_2, CH_4). The methods on which the inventories are based generally estimate GHG emissions as a function of activity data (e.g., electricity usage, cement production, fertilizer consumption, etc.) and activity- and gas-specific emission factors.

Under Section 1605 of the Energy Policy Act of 1992, DOE through the Energy Information Administration (EIA) was directed to develop, based on data available, an inventory of the national aggregate emissions of each GHG between 1987 and 1990, and to issue guidelines for annual voluntary collection and reporting of information on sources of GHG emissions. On February 14, 2002, the President directed the Secretary of Energy, working with the Secretaries of Commerce and Agriculture, and the Administrator of the EPA, to propose improvements to the current GHG registry to "enhance measurement accuracy, reliability and verifiability, working with and taking into account emerging domestic and international approaches." On November 9, 2006, EIA submitted the "Voluntary Reporting of Greenhouse Gases, Form EIA-1605" to the Office of Management and Budget for review and a three-year extension under the Paperwork Reduction Act of 1995. A Federal Register Notice was issued on that date with comments requested by December 11, 2006. The revised reporting form, instructions, and Simplified Emissions Inventory Tool (SEIT) can be found at http://www.eia.doe.gov/oiaf/1605/forms.html. The revised guidelines emphasize the importance of providing a full accounting of all domestic and international GHG emissions, sequestration activities and emission reductions. The revised guidelines also include "state-of-the-science" guidance and tools for estimating emissions from agricultural, forestry, and conservation activities important for carbon sequestration efforts. The revised guidelines enable the DOE to recognize those participants in the program that provide an accurate and complete accounting of their GHG emissions and activities to reduce, avoid and sequester their GHG emissions. Under the revised guidelines, utilities, manufacturers and other businesses that emit GHGs will be able to register their emission reductions achieved after 2002 if they also provide entity-wide emissions inventory data (DOE, 2005).

3.2.2 State Air Quality

This section summarizes air quality for each state. Table 3-3 provides information on climate types, major sources of GHGs, and nonattainment areas for each state.

3.2.2.1 Alabama Air Quality Summary

Although improvements in air quality had been made in the early 1990s, monitoring data in the Birmington area since 1995 has shown nonattainment of the 1-hour O_3 standard. In 2001, there were 12 days exceeding the 8-hour O_3 standard and 3 days that exceeded the 1-hour O_3 standard. Ozone problems in Alabama are attributable to the southeastern U.S. having high natural VOC emissions, high temperatures, and a high probability of stagnation. Also, the Gulf Coast has land/sea breeze driven recirculation, stagnation, and convergence that concentrate and enhance reactivity of local emissions (Alabama, 2001).

3.2.2.2 Alaska Air Quality Summary

Alaska has experienced numerous exceedances of the PM-10 standard over the past twenty years and will continue to suffer from high levels of coarse fraction particulate well into the 21st Century. While the PM-10 problem in Southeast Alaska was primarily related to woodstove use, dust that was re-entrained from unpaved roads and winter traction sand did contribute to localized PM-10 exceedances. The summer of 2004 was the third driest summer on record, and wildfires burned the largest amount of acreage in recorded Alaska history (approximately 6.7 million acres). Smoke drifted over much of the state and concentrations were often in the "unhealthy," "very unhealthy," and "hazardous" ranges. Air Quality Alerts and Advisories were issued between June 28 and September 17, 2004 (Alaska, 2001).

3.2.2.3 Arizona Air Quality Summary

Concentrations of CO, lead and SO_2 have dramatically improved since requirements began in the 1970s, and all monitors for these pollutants have shown compliance with health standards in recent years. In April 2004, EPA designated a new 8-hour O_3 nonattainment area as encompassing the northeastern portion of Maricopa County and a very small portion of northeastern Pinal County. In September 2003, EPA issued a finding that the Phoenix metropolitan nonattainment area met a Dec. 31, 2000, deadline to comply with CO standards. The action moved the Phoenix metropolitan area a step closer to qualifying for designation as an attainment area for CO (Arizona, 2004).

3.2.2.4 Arkansas Air Quality Summary

Arkansas' most significant air pollution concern continues to be ground-level O_3 from pollutants common in metropolitan areas. However, days where air quality was unhealthy for sensitive groups for O_3, CO and PM dropped from 7 in 2002 to 1 in 2003. In 2003, Arkansas was in compliance with its 8-hour O_3 standard (Arkansas, 2003).

3.2.2.5 California Air Quality Summary

Air quality as it relates to O_3 has improved greatly in California over the last several decades, although not uniformly throughout the State. However, despite aggressive emission controls, maximum measured values exceed the national 1-hour O_3 standard in seven air basins and exceed the national 8-hour O_3 standard in 10 air basins. California's highest O_3 concentrations occur in the South Coast Air Basin, where the peak 1-hour indicator is close to two times the state standard. Ozone concentrations are generally lower near the coast than they are inland, and rural areas tend to be cleaner than urban areas. Most areas of California have either 24-hour or annual PM-10 concentrations that exceed the State standards. The highest annual average values of PM-10 during 2003 occurred in the Salton Sea, Great Basin Valleys, South Coast, San Joaquin Valley, and San Diego Air Basins. The State and national CO standards are now attained in most areas of California. The requirements for cleaner vehicles and fuels have been primarily responsible for the reductions in CO, despite significant increases in population and the number of vehicle miles traveled each day. However, there is still one problem area: the City of Calexico in Imperial County. While CO concentrations continue to decrease throughout most of the State, the CO problem in Calexico is unique in that this area shares a border with Mexico (California, 2005).

3.2.2.6 Colorado Air Quality Summary

For several years the Denver-metropolitan area had not violated any NAAQS for criteria pollutants. However, in the summer of 2003, ground level O_3 readings violated the new 8-hour standard and subsequently implemented an action plan to reduce O_3 levels. No violations of the PM-10, PM-2.5, or CO standards have occurred in the last 10 years. Studies have shown that the Denver Brown Cloud is caused by local, not regional emissions and have shown that chemical reactions in the atmosphere turn sulfates, nitrates and organic carbon into particles that cause the Brown Cloud. The largest single source of the Brown Cloud is motor vehicle use. Denver's meteorology and topography contribute to the Brown Cloud when pollutants are trapped in the Denver basin by air inversions (Colorado, 2004).

3.2.2.7 Connecticut Air Quality Summary

In 2004, 3 of 11 O_3 monitoring sites exceeded the level of the 1-hour ozone standard and 1 of 11 sites reported a fourth-highest daily 8-hour average O_3 concentration above the level of the 8-hour NAAQS. The number of monitoring sites recording 1-hour O_3 exceedances has varied between 3 and 11 (out of 11 total sites) per year between 1999 and 2004. These observed increases/decreases correspond to changing summer weather conditions. Warm and dry summers, with more frequent periods of air stagnation and/or pollution transport conditions, generally record increased exceedances of the ozone NAAQS. No exceedances of any other criteria pollutants were recorded in the state in 2004 (EPA, 2005).

3.2.2.8 Delaware Air Quality Summary

In 2004, there were several days when the 8-hour O_3 and PM2.5 standards were exceeded in Delaware. New Castle County has been designated non-attainment for PM2.5. There were no other exceedances of criteria pollutants in the state in 2004 (Delaware, 2004).

3.2.2.9 Florida Air Quality Summary

Florida is one of only 3 states east of the Mississippi River to meet all NAAQS. However, some areas of the state experience a few days each year when levels of ground-level O_3 or particles may be high enough to affect sensitive persons. There were 35 exceedances of the 8-hour standard in 2003; however, none have contributed to a violation of the standard (Florida, 2003).

3.2.2.10 Georgia Air Quality Summary

In 2004, Georgia had 19 exceedances of the 8-hour O_3 standard and 2 exceedances of the 1-hour O_3 standard. Georgia maintained compliance with all other NAAQS standards in 2004 (Georgia, 2004). In 2003, the only part of Georgia to not meet a NAAQS is the Atlanta Metropolitan 13 county non-attainment area (Clayton, Fulton, Rockdale, Cherokee, Gwinnett, Cobb, Forsyth, Dekalb, Fayette, Paulding, Douglas, Coweta, and Henry) for 1-hour O_3 (Georgia, 2003).

3.2.2.11 Hawaii Air Quality Summary

There have been no exceedances of any NAAQS in Hawaii over the last several years and most measurements show criteria pollutant levels well below national standards (EPA, 2006).

3.2.2.12 Idaho Air Quality Summary

The cities of Pocatello and Chubbuck typically experience high particulate levels (PM-10) from November to February. The air quality for the Portneuf Valley has consistently and dramatically improved over the past 10 years. The winter of 2002-2003 was the first where PM-10 levels were in the "good" category each day and PM-2.5 levels did not exceed the "moderate" category. The last recorded PM-10 air quality violation occurred in 1993 (Idaho, 2004).

3.2.2.13 Illinois Air Quality Summary

In 2002, air-monitoring equipment recorded six days when O_3 levels exceeded the 1-hour standard for O_3. Two of the days occurred in the Metro East region, and the remaining four occurred in the Chicago metropolitan area. According to the Air Quality Index (AQI), Illinois had 4 days when air quality was considered "red" or "unhealthy" and 34 days when air quality was considered "orange" or "unhealthy for sensitive groups" in one or more portions of the State in 2002. Of the 34 "orange" days, 30 were for 8-hour O_3, 11 were for PM-2.5 (fine particles), and 7 were both PM-2.5 and O_3 (Illinois, 2002).

3.2.2.14 Indiana Air Quality Summary

Indiana's air continues to improve. Emission reductions programs, that mandate stricter regulations for vehicles and industry, have reduced smog and dust levels. Indiana's air meets the NAAQS for SO_2, NO_2, CO, Pb, and PM-10 at air quality monitors located across the state. There are still areas and pollutants of concern to address. Some parts of Indiana still exceed the 1-hour O_3 standard and the 8-hour health standard for O_3 on some hot, sunny days. Air monitoring also shows that some areas of the state have levels of PM-2.5 that exceed the NAAQS. Levels of toxic chemicals, for which there are no federal health standards, are also of concern in Indiana (Indiana, 2004).

3.2.2.15 Iowa Air Quality Summary

Iowa has no areas designated nonattainment. In 2003, there was only one NAAQS exceedance. This exceedance was measured at Lake Sugema State Park for O_3 (Iowa, 2003). In 2004 there were 3 days where locations had AQI values over 100 due to PM, which is considered unhealthy for sensitive populations (Iowa, 2004).

3.2.2.16 Kansas Air Quality Summary

The ground level O_3 or smog problem develops in Kansas during the period from April through October due to high-pressure systems that stagnate in the summer months, characterized by cloudless skies, high temperatures and light winds. Upper air inversions also cause pollution concentrations to increase near the ground from pollution sources. Kansas has a long history of particulate matter problems caused by its weather. The Great Dust Bowl of the 1930s was caused in part by many months of minimal rainfall and high winds. Although this natural source of particulate matter pollution is still a concern today, it is not as severe as in the 1930s. Kansas has no areas in exceedance of the NAAQS (Kansas, 2004).

3.2.2.17 Kentucky Air Quality Summary

All Kentucky counties are currently in attainment of the standards for CO. There were no exceedances of any of the SO_2 standards in 2003. There were no exceedances of the NO_2 standard in 2003, and there have been no recorded exceedances of the NAAQS since the inception of sampling in 1970. Statewide and regional NO_2 levels show steady downward trends primarily due to the use of pollution control devices on motor vehicles, power plants and industrial boilers. In 2003 there were 25 exceedances of the 8-hour O_3 standard. Only preliminary attainment designations have been made based on 8-hour readings. All Kentucky counties are currently in attainment with the PM-10 standards. Statewide and regional PM-10 levels have shown declining trends. There were no exceedances of the 24-hour PM-2.5 standard in 2003. Five samplers exceeded the annual standard with four of those occurring in Jefferson County and the fifth in Fayette County (Kentucky, 2003).

3.2.2.18 Louisiana Air Quality Summary

In 2000, there were 8 days where one or more areas exceeded the 1-hour O_3 standard. Ground level O_3 presents a significant air quality problem in the Baton Rouge area during the summer months. Between 1990 and 1997, the Baton Rouge area experienced between 2 and 16 days each summer when federal air quality standards were violated (Louisiana, 2000).

3.2.2.19 Maine Air Quality Summary

There were no recorded exceedances of any NAAQS standards in Maine in 2004. Air monitoring for Pb has been discontinued because the concentration of lead in the air in Maine has been well below the NAAQS for many years (EPA, 2005).

3.2.2.20 Maryland Air Quality Summary

All of Maryland is in attainment for PM, NO_2, SO_2, Pb and CO. Large parts of Maryland are nonattainment for O_3 including Central Maryland, the Baltimore Metropolitan region, the Washington Metropolitan region, part of Southern Maryland and part of the Eastern Shore (Maryland, 2004).

3.2.2.21 Massachusetts Air Quality Summary

In 2004, 1 out of 15 monitoring sites measured O_3 levels above the NAAQS. Between 1999 and 2004 the number of monitoring sites recording O_3 levels above the NAAQS ranged from 1 to 11 (out of 15 total). This variation has been attributed differing summer weather conditions from year to year. No other exceedances of the NAAQS were recorded in 2004 (EPA, 2005).

3.2.2.22 Michigan Air Quality Summary

In 2003, all Michigan areas were in attainment with both the 1 hour and 8-hour CO standards. There are no large sources of Pb in Michigan and point source-oriented monitoring is not being conducted in the state. For Michigan, ambient NO_2 levels have always been well below the NAAQS (less than half).

When the monitoring data were averaged over a 3-year period between 1999 and 2003, there were only a total of 4 sites in all of Michigan that either met or were below the 8-hour O_3 standard. All areas of Michigan are in attainment with the PM-10 NAAQS since October 4, 1996. Overall, in 2003 there were seven PM-2.5 monitoring sites that were above NAAQS. These sites were all in Southeast Michigan. On October 20, 1982, the last remaining SO_2 nonattainment area in Michigan was redesignated to attainment (Michigan, 2003).

3.2.2.23 Minnesota Air Quality Summary

Annual averages of peak 1-hour and 8-hour O_3 concentrations are increasing at all monitoring sites in the Twin Cities, including a site in Blaine. Only at sites to the far north (Ely and Mille Lacs) are O_3 trends improving. Currently, Minnesota is in compliance with the new national air quality standard for O_3. However in the last two years, the Minnesota Pollution Control Agency has issued air pollution health alerts for O_3: four times in 2001, and once in 2002. These are the first alerts issued for O_3 since the 1970s. Over the five years from 1996 to 2000, CO_2 emissions from fossil fuel burning in Minnesota rose an average of 1.2 percent per year. These increases reflect a continuing increase in the electric utility and transportation sectors. From 1999 to 2000, CO_2 emissions increased 5.6 percent (Minnesota, 2003).

3.2.2.24 Mississippi Air Quality Summary

Based on 2001 to 2003 air monitoring data, all counties in Mississippi are attaining the new O_3 standard and on April 15, 2004, the EPA designated all counties in the state attainment with the 8-hour ground-level O_3 standard. Current monitoring data indicates that all areas of the state will attain the PM-2.5 standard (Mississippi, 2004).

3.2.2.25 Missouri Air Quality Summary

During 2002, Missouri met the NAAQS for O_3. In 2000, the Missouri Air Conservation Commission adopted a statewide rule to reduce NO_x emissions, intended to improve air quality in the St. Louis O_3 nonattainment area. Since 1993, facilities reduced PM-10 emissions by 59 percent, while VOC emissions dropped nearly 48 percent. SO emissions dropped 40 percent and NO_x emissions dropped 31 percent. There has been a 30 percent decrease in Pb emissions since 1993 (Missouri, 2002).

3.2.2.26 Montana Air Quality Summary

PM is Montana's major air pollution problem. The major sources of particulate are re-entrained road dust from passing vehicles on paved and unpaved roads, residential wood combustion, and industrial and agricultural activity. Since the promulgation of the PM-10 standards, several areas in Montana have been designated nonattainment including Butte, Columbia Falls, Kalispell, Libby, Missoula, Thompson Falls, and Whitefish. SO_2 is a pollutant of concern in the State and there are 4 areas in Montana where SO_2 is an issue. These are Great Falls in Cascade County, East Helena in Lewis & Clark County, Colstrip in Rosebud County; and the Billings/Laurel area in Yellowstone County. Pb is a pollutant of concern in East Helena where the predominant source is the ASARCO primary lead smelter. CO is a pollutant of concern in the larger communities in Montana and in West Yellowstone due to snowmobile activity in the winter. Currently, Missoula is categorized as “moderate” nonattainment for CO. All areas of the state are considered attainment for O_3 (Montana, 2003).

3.2.2.27 Nebraska Air Quality Summary

Of all pollutants monitored throughout the state in 2002, only Total Reduced Sulfur (TRS) exceeded its respective standards. The TRS standard was exceeded in Dakota City. TRS is not a NAAQS but a state standard. SO_2 measurements are well below the NAAQS. Although PM-10 exceedances have been recorded in Weeping Water in previous years, no exceedances were recorded in 2002. The O_3 NAAQS has never been exceeded at any site (Nebraska, 2002).

3.2.2.28 Nevada Air Quality Summary

Las Vegas Valley is designated a serious nonattainment area for CO and PM. The Truckee Meadows basin is designated as a moderate nonattainment area for CO and a serious nonattainment area for PM. Both areas experience elevated O_3 concentrations during the summer months. Anticipated standard changes may result in the classification of both areas as nonattainment for O_3. Because Nevada is a highly urbanized state, about 80 percent of the state's population lives within the PM and CO nonattainment areas (Nevada, 2001).

3.2.2.29 New Hampshire Air Quality Summary

There were no exceedances of the NAAQS in New Hampshire in 2004 and air pollution levels are well below primary and secondary NAAQS for CO, SO_2, NO_2, and PM10. In 1996 New Hampshire discontinued monitoring of Pb because historically Pb concentrations declined to the point where virtually no Pb was detectible at monitoring sites (EPA, 2005).

3.2.2.30 New Jersey Air Quality Summary

In 2003, New Jersey had numerous exceedances of the 1- and 8-hour O_3 NAAQS. Every county in New Jersey has been designated non-attainment for the 8-hour O_3 standard with the most severe ratings being in the northern and eastern regions of the state. There were no exceedances of any other criteria pollutants in 2003 (New Jersey, 2003).

3.2.2.31 New Mexico Air Quality Summary

Exceedances of EPA pollutant standards have occurred at 3 sites in the state. A small area around Sunland Park in Dona Ana County is designated non-attainment for O_3, at the lowest non-attainment level called marginal. An area around Anthony, also in Dona Ana County, is designated non-attainment for PM-10. This area, and other areas in Dona Ana County, experience high particulate levels during high wind events, especially in the spring and fall. Although the high levels occur because of natural events, the Bureau has put into place the Natural Events Action Plan (NEAP) in order to mitigate any man-made contributions such as uncontrolled construction sites. The third non-attainment area is located in Grant County, around the town of Hurley, where SO_2 standards were exceeded in the 1970s before the copper smelters installed control equipment. This area is soon to be designated in-attainment with the SO_2 standard (New Mexico, 2005).

3.2.2.32 New York Air Quality Summary

The Statewide PM-10 levels, SO_2 levels and CO levels in New York Levels are all below the ambient air quality standards (New York Department of Environmental Conservation, 2005a). The levels of ozone have been systematically declining in New York State during the past two decades. This decline is the result of motor vehicle exhaust emission controls, lower volatility fuels, stringent control of industrial pollution sources, and other measures that have reduced ozone precursors. Unhealthful ozone levels do still occur, however, particularly in New York City and the lower Hudson Valley. The NY Department of Environmental Conservation's (DEC) ozone monitoring network provides real-time information on ozone concentrations to the general public, and meets state and federal requirements. The ozone advisories are developed based on DEC's constant monitoring of ozone levels at 30 sites across the state. Recent results of ozone monitoring can be found in the New York State Ambient Air Quality Report. In addition, the DEP has been monitoring the ambient outdoor air for asbestos following the World Trade Center (WTC) disaster. This effort augmented ambient air asbestos sampling performed by the EPA and other state and city agencies (New York Department of Environmental Conservation, 2005b).

3.2.2.33 North Carolina Air Quality Summary

The EPA presented North Carolina its national Clean Air Excellence Award in March 2004 in recognition of the state's innovative Clean Smokestacks Act aimed at reducing multiple air pollutants. Under the act, coal-fired power plants must achieve a 77-percent cut in NO_x emissions by 2009 and a 73-percent cut in SO_2 emissions by 2013. These emissions cuts should lead to significant reductions in O_3, haze, fine particles and acid rain. Although the act does not set caps on mercury, the controls needed to meet the NO_x and SO_2 limits will reduce mercury emissions substantially. In 2000, there were 6 exceedances of the 1-hour standard, all of which occurred on three days in June. In 2000, the 8-hour standard was exceeded 239 times, on 35 different days, with 5 counties having 10 or more exceedances at individual sites (North Carolina, 2002).

3.2.2.34 North Dakota Air Quality Summary

There were no SO_2, NO_2, O_3 or PM exceedances of either the state or NAAQS measured during 2003. North Dakota is one of 14 states that are in attainment for all criteria pollutants. North Dakota has also been designated "attainment" for both the fine particulate and the 8-hour O_3 standards (North Dakota, 2004).

3.2.2.35 Ohio Air Quality Summary

SO_2 levels in urban areas have dropped an average of 16.7 percent in the last ten years. There were no violations of SO_2 air quality standards in 2003. All areas except Geauga County, which had 5 exceedances, are in attainment of the 1-hour O_3 standard. Two counties are in attainment of the 8- hour standard. There are 32 counties with monitored non-attainment based on data for 2001 through 2003. No violations of air quality standards for NO_2 were recorded in 2003 (Ohio, 2003).

3.2.2.36 Oklahoma Air Quality Summary

Data continues to indicate that O_3 levels have decreased from previous years in Oklahoma. Ozone monitors recorded exceedances of the 8-hour O_3 standard on 27 days in 2000, 15 days in 2001 and only 13 days in 2002 and 2003. All sites are in compliance with the PM-2.5 standard (Oklahoma, 2004).

3.2.2.37 Oregon Air Quality Summary

Motor vehicles are now the number one source of air pollution in Oregon. Emissions from cars contribute to ground level O_3 (smog) pollution especially on hot summer days. Smog is a problem in the Portland, Eugene, Salem and Medford areas. Oregon communities had minimal NAAQS exceedances and no violations (Oregon, 2003).

3.2.2.38 Pennsylvania Air Quality Summary

There were no exceedances of ambient air quality standards for PM-10 in 2001. Four sites exceeded the PM-2.5 24-hour standard in 2001. Pb levels have been in compliance for over 10 years. In 2001, averages for SO_2 were 50 percent below the annual ambient air quality standard. Ozone concentrations exceeded the 1-hour daily standard on 4 days and exceeded the 8-hour maximum daily level on 39 days during 2001. NO_2 levels have improved 11 percent between 1991 and 2001 and there were no exceedances of the standard in 2001. CO levels have improved 29 percent since 1992 and there were no exceedances of the standard in 2001 (Pennsylvania, 2001).

3.2.2.39 Rhode Island Air Quality Summary

In 2004, 2 of 3 ozone monitoring sites each reported one exceedance of the 1-hour O_3 NAAQS and 1 of 3 O_3 sites reported a fourth highest 8-hour average O_3 concentration exceeding the NAAQS. There were no other exceedances of any criteria pollutants in 2004 (EPA, 2005).

3.2.2.40 South Carolina Air Quality Summary

All areas of South Carolina were in attainment with the 1-hour O_3 standard in 2000. In fact, South Carolina is currently only one of 15 states meeting all NAAQS in 2000 (South Carolina, 2000).

3.2.2.41 South Dakota Air Quality Summary

South Dakota has no areas designated nonattainment. South Dakota is located in the high plains that is subject to periods of droughts and high winds. These are the main ingredients for fugitive dust problems. Fugitive dust is identified as dust from mining activity, gravel roads, construction activity, street sanding operations, and wind erosion from agricultural fields. Fugitive dust is the main problem in Rapid City (South Dakota, 2004).

3.2.2.42 Tennessee Air Quality Summary

Currently Tennessee has two counties (Knox, Hamilton) in violation of the PM-2.5 federal standard. Based on data for 2000 through 2002, a number of areas may not be in attainment of the 8-hour O_3 standard. A review of ambient O_3 data generated by the State of Tennessee's O_3 monitoring network from March 1, 2002 through October 31, 2002 shows the level of the old 1-hour standard of 0.12 ppm was exceeded at 1 site on 1 day and the level of the new 8-hour standard of 0.08 ppm was exceeded at numerous sites on 54 different days (Tennessee, 2002).

3.2.2.43 Texas Air Quality Summary

Four areas in Texas (Houston/Galveston/Brazoria, Beaumont/Port Arthur, Dallas/Fort Worth, and El Paso) are in nonattainment of the 1-hour O_3 standard. Ozone formation tends to be highest from March through October in Texas. In 2004, there were 41 days where the 1-hour O_3 standard was exceeded by one or more areas (Texas, 2004).

3.2.2.44 Utah Air Quality Summary

Utah is in compliance with both the 1-hour and the 8-hour O_3 standard and meets federal standards for both PM-10 and PM-2.5. Nevertheless, high concentrations of particulate matter are brought on by wintertime episodes of air stagnation and temperature inversion. As such, there are periods during the winter months when ambient concentrations approach the standards. In 2003, Utah submitted a plan to the EPA showing that Utah County would continue to show compliance with the federal PM-10 standards for the next ten years. Utah was in compliance with the CO standards in 2003 (Utah, 2003).

3.2.2.45 Vermont Air Quality Summary

In 2004, there were no exceedances of any NAAQS. Vermont did not conduct monitoring for Pb in 2004 because historical concentrations of Pb have been extremely low (EPA, 2005).

3.2.2.46 Virginia Air Quality Summary

In 2004, there were 2 days where one or more areas exceeded the 1-hour O_3 standard. These exceedances occurred in Alexandria, Fairfax County and Loudoun County in July. There were 6 days where the 8-hour O_3 standard was exceeded. These exceedances occurred in the time period May to July in 12 counties (Virginia, 2004).

3.2.2.47 Washington Air Quality Summary

From the period 1999 to 2002, there was one exceedance of the PM-10 standard each year. There was one exceedance of the 8 hour O_3 standard at Enumclaw for both 2000 and 2001. There were no exceedances of CO between 2000 and 2002. EPA designated the central Puget Sound and Vancouver areas nonattainment for the 1-hour O_3 standard. Both standards apply to Washington until June 15, 2005. On that date, EPA will revoke the 1-hour standard and leave the 8-hour standard as the sole O_3 standard. Washington must submit maintenance plans to EPA for the central Puget Sound and Vancouver areas by June 15, 2007 (Washington, 2004).

3.2.2.48 West Virginia Air Quality Summary

Ground-level O_3 is one of West Virginia's recurring air pollution problems. All monitoring sites have shown consistent averaged values that are well below the 24-hour and annual PM-10 NAAQS. Berkeley, Brooke, Cabell, Hancock, Jefferson, Kanawha, Marion, Marshall, Ohio, Putnam, Wayne, and Wood counties do not meet the PM-2.5 NAAQS. Over the last decade, the annual average SO_2 level in the ambient air has been well below the standard. In 2003, all sites except one reported levels below the 1-hour and the 8-hour standard for CO (West Virginia, 2003).

3.2.2.49 Wisconsin Air Quality Summary

There was only one Ozone Action Day in 2004 in Wisconsin (Wisconsin, 2004). However, Wisconsin issued its first statewide air health advisory on February 1, 2005 based on the presence of persistently elevated levels of fine particles in the air, recorded at seven air quality monitoring stations located around the state (Wisconsin, 2005). The combination of moist, warm air with stagnant weather conditions, together with the input of particulate emissions from power plants, motor vehicle operation and other fuel burning sources led to the Orange level health advisory. At the same time, similar advisories were issued in number of Ohio cities, six Indiana counties, and in Minnesota, Iowa, Illinois and Pennsylvania.

3.2.2.50 Wyoming Air Quality Summary

Wyoming has no nonattainment areas, however, the state is developing a long-term plan to improve air quality.

Table 3-3. Climate Types, Major Sources of GHGs, and Nonattainment Areas in the States

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Alabama	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (98%), the majority of which is due to transportation petroleum and utility coal. Minor emissions came from cement production, lime manufacture, and limestone use (2%). Carbon dioxide sinks (non-fuel usage, timber stock, and other forest resources) offset about 17%of the total CO_2 emissions. Sources of CH_4 emissions were coal mining (57%), landfills (27%), domesticated animals (9%), manure management (4%), natural gas/oil extraction (3%), fossil fuel combustion (<1%), and wastewater (<1%). N_2O emissions were attributable to fossil fuel combustion (61%), and agricultural soils (39%).	PM-2.5 (1) 8-Hour O_3 (1)
Alaska	Marine West Coast/Subarctic/ Tundra	N/A	PM-10 (2)
Arizona	Semiarid/ Desert	N/A	PM-10 (8) SO_2 (4)
Arkansas	Humid Subtropical	N/A	None

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
California	Marine West Coast/ Mediterranean/ Desert	CO_2 accounted for the majority of California's emissions. These emissions were primarily due to the burning of fossil fuels, especially in the transportation sector (about 52 percent of total CO_2 emissions). Nitrous oxide (N_2O) emissions fluctuated between 1990 and 2002, with the majority of these emissions from agricultural soils and mobile source combustion. Over the 13-year period, emissions from agricultural soils generally increased while emissions from mobile source combustion generally decreased. CH_4 was the third largest contributor to California's emissions in 1990 and in 2002, equal to 8.5 MMTCE in both years. CH_4 emissions were fairly constant over the time period and were mostly from landfills and enteric fermentation. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) each made up a small share of the total emissions. These emissions increased between 1990 and 2002, with 2002 emissions of these gases approximately 74% above 1990 levels. This increase in HFC/PFC/SF6 emissions is largely due to the replacement of ozone-depleting substances (CFCs) with HFCs, which have high global warming potentials.	PM-2.5 (2) PM-10 (10) CO (1) 8-Hour O_3 (15)
Colorado	Semiarid	The major source of CO_2 emissions was fossil fuel combustion (99%), with minor emissions from land use, lime manufacture, and cement manufacturing (1%). Contributors to CH_4 emissions were domesticated animals (45%), coal mining (23%), landfills (18%), oil and natural gas systems (11%), and minor emissions from manure management and wastewater treatment (3%). The sole source of N_2O emissions were fertilizer use.	8-Hour O_3 (1)
Connecticut	Humid Continental (Hot Summer)	CO_2 accounted for the majority of Connecticut's emissions. These emissions were mostly due to the burning of fossil fuels, primarily for transportation; electricity production; and energy consumption in the residential sector. CH_4 was the second largest contributor to Connecticut's emissions in 1990 and in 2000, equal to 0.8 and 0.5 MMTCE respectively. CH_4 emissions decreased slightly over the time period; these emissions resulted from the anaerobic decay of solid waste in landfills and, to a lesser extent, emissions from natural gas and oil systems. N_2O emissions were fairly constant, amounting to 0.4 MMTCE in 1990 and 2000, and were mostly from mobile source combustion and waste combustion. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) each comprised a small share of the total emissions. These emissions increased from 0.1 to 0.2 MMTCE between 1990 and 2000. This increase in HFC/PFC/SF6 emissions is largely due to the replacement of ozone-depleting substances (CFCs) with HFCs, which have high global warming potentials.	8-Hour O_3 (1)
Delaware	Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (>99%), with minor emissions from agricultural application of lime, and lime manufacture. Almost half of the emissions from fossil fuel combustion came from the utility sector. Combustion of fossil fuels accounted for over 95% of total greenhouse gas emissions. Contributors to CH_4 emissions were landfills (76%), manure management (14%), domesticated animals (8%), and municipal wastewater (2%). N_2O emissions were attributable to fertilizer use. Delaware did not evaluate sources and sinks (i.e., an increase in forest carbon storage) associated with land use.	None
District of Columbia	Humid Continental (Hot Summer)	N/A	PM-2.5 (1) 8-Hour O_3 (1)
Florida	Humid Subtropical	The only source of CO_2 emissions evaluated in the inventory was fossil fuel combustion. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 5% of the total CO_2 emissions. Sources of CH_4 emissions were landfills (75%), domesticated animals (19%), and manure management (6%). Nitrous oxide emissions were attributable to agricultural soil management (81%) and manure management (19%). Emissions of HFCs, PFCs, and SF_6 were due to the use of substitutes for O_3 depleting substances.	None

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Georgia	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (98%), with minor emissions from cement production, limestone use, and soda ash consumption. In particular, coal used for utilities accounted for 41% of emissions from fossil fuel combustion, and use of petroleum for transportation comprised of 37% of emissions from fossil fuel combustion. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 11% of the total CO_2 emissions. Contributors to CH_4 emissions were waste (52%), manure management (28%), domesticated animals (15%), natural gas systems (5%), and burning of agricultural waste (<1%). The sources of N_2O emissions were fertilizer use and the burning of agricultural waste.	PM-2.5 (3) 8-Hour O_3 (3)
Hawaii	Tropical Rain Forest	The major source of CO_2 emissions was fossil fuel combustion (99%) with minor emissions (<1%) from cement production and waste combustion. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 6% of the total carbon dioxide emissions. Contributors to methane emissions included landfills (57%), fossil fuel combustion (20%), domesticated animals (14%), manure management (6%), wastewater treatment (1%), and agricultural burning (<1%). The sources of N_2O emissions were fossil fuel combustion (83%), agricultural soils management (16%), the burning of agricultural waste (<1%), and waste combustion (<1%).	None
Idaho	Humid Continental (Warm Summer)	N/A	PM-10 (5)
Illinois	Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (99%), the majority of which is due to transportation petroleum and utility coal. Illinois estimated emissions associated with land use, but did not estimate land use-related sinks (i.e., an increase in forest storage carbon), which most states (and nationally) far exceed emissions. Sources of CH_4 emissions were landfills (66%), coal mining and natural gas production (23%), manure management (7%), and domesticated animals (4%). Nitrous oxide emissions were attributable to fertilizer use.	PM-2.5 (2) 8-Hour O_3 (2)
Indiana	Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (99%) with minor emissions from cement production (<1%). Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 1% of the total CO_2 emissions. Contributors to CH_4 emissions included landfills (47%), manure management (18%), domesticated animals (15%), coal mining (10%), natural gas production (8%), and fossil fuel combustion (3%). Nitrous oxide emissions were accounted for by fertilizer use (77%) and fossil fuel combustion (23%).	PM-2.5 (6) 8-Hour O_3 (4)
Iowa	Humid Continental (Warm Summer/Hot Summer)	The majority of Iowa's emissions came from CO_2, with the burning of fossil fuels, primarily for the production of electricity, constituting the majority of the CO_2 emissions in both years. There was a significant emissions increase in N_2O between 1990 and 2000, which was a result of a change in methodology for calculating soil emissions. Adequate soil data was not available to recalculate the 1990 estimate. It is unlikely that actual soil emissions varied significantly between the two years, though more sources of soil emissions were identified. CH_4 was the second largest contributor to Iowa's emissions in 1990 and third largest contributor in 2000. These emissions were mostly from landfills, manure management, and domesticated animals. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) each comprised a small share of the total emissions as well.	None

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Kansas	Semiarid/ Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (85%), most of which (70%) was accounted for by the electric utility and transportation sectors. Contributors to CH_4 emissions included domesticated animals (76%), landfills (12%), manure management (7%), and minor emissions from mining and extraction of natural gas, oil, and coal, and wastewater treatment. Sources of N_2O emissions included fertilizer use (90%) and industrial processes (10%). Kansas did not evaluate sources and sinks (i.e., an increase in forest carbon storage) associated with land use.	None
Kentucky	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (96%), the majority of which is utility coal. Minor emissions came from cement and lime production and forest/grassland conversion. Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 26% of the total CO_2 emissions. Sources of CH_4 emissions were coal mining (73%), domesticated animals (12%), landfills (10%), manure management (3%), and natural gas/oil extraction (2%). Nitrous oxide emissions were from fertilizer use. Sources of perfluorocarbons were HCFC-22 production (91%) and aluminum production (9%).	PM-2.5 (2) 8-Hour O_3 (3) SO_2 (1)
Louisiana	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (99%), with minor emissions from lime manufacture, limestone use, CO_2 production, electric utilities and semiconductors, and agricultural soil management. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 10% of the total CO_2 emissions. Sources of CH_4 emissions were natural gas and oil extraction (51%), landfills (25%), rice cultivation (14%), domesticated animals (9%), and manure management (1%). N_2O emissions were attributable to nitric acid production (61%) and agricultural soil management (39%). Emissions of HFCs and SF_6 were due to HCFC-22 production and electric utilities and semiconductors.	8-Hour O_3 (1)
Maine	Humid Continental (Warm Summer)	The major source of carbon dioxide emissions was fossil fuel combustion (99%), with minor emissions from cement production (<1%). Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 12% of the total carbon dioxide emissions. Contributors to methane emissions were landfills (84%), domesticated animals (11%), manure management (2%), fossil fuel combustion (2%), and wastewater (1%). Fertilizer use (99%) and fossil fuel combustion (1%) accounted for nitrous oxide emissions.	8-Hour O_3 (2)
Maryland	Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (97%), with minor emissions from land-use conversion (2%) and from cement production and lime manufacture (1%). Fossil fuel combustion for transportation and utilities comprised over 65% of the CO_2 emissions from fossil fuel combustion, primarily from use of coal and petroleum. Contributors to CH_4 emissions were landfills (60%), manure management (15%), coal mining (13%), domesticated animals (10%), and fossil fuel combustion (2%). Nitrous oxide emissions were accounted for fuel combustion (2%). Nitrous oxide emissions were accounted for by fossil fuel combustion (87%) and fertilizer use (13%).	PM-2.5 (2) 8-Hour O_3 (3)
Massachusetts	Humid Continental (Hot Summer)	The major source of carbon dioxide emissions was fossil fuel combustion (98%). Emissions from waste combustion (2%) and lime manufacturing and limestone use (<1%) comprised the remainder of the carbon dioxide emissions. Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 10% of the total carbon dioxide emissions. Contributors to methane emissions included landfills (91%), domesticated animals and manure management (4%), fossil fuel combustion (3%) and wastewater treatment (2%). The primary source of nitrous oxide emissions was fossil fuel combustion (>99%), with minor emissions from fertilizer use (<1%).	8-Hour O_3 (2)

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Michigan	Humid Continental (Hot Summer)	CO_2 accounted for the vast majority of Michigan's emissions. These emissions were due in large part to the burning of fossil fuels, primarily for transportation and the production of electricity. CH_4 was the next largest contributor, mostly from the anaerobic decay of solid waste in landfills. N_2O, the third largest contributor, came chiefly from agricultural soil management and mobile source combustion. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) each made up a small share of the total emissions as well. The increase in HFC/PFC/SF6 emissions in 2002 was largely a result of the replacement of ozone-depleting substances (CFCs) with HFCs, which have high global warming potentials.	PM-2.5 (1) 8-Hour O_3 (12)
Minnesota	Humid Continental (Warm Summer)	The major source of CO_2 emissions was fossil fuel combustion (>99%), with minor emissions from waste combustion, limestone use, CO_2 manufacture, and agricultural soils (<1%). Of those CO_2 emissions from fossil fuel combustion, 79% were attributable to coal use for the utility sector and petroleum use for transportation. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 10% of the total CO_2 emissions. Contributors to CH_4 emissions were landfills (39%), domesticated animals (39%), manure management (13%), natural gas and oil systems (7%), fossil fuel combustion (1.9%), and rice cultivation (<1%). The majority of N_2O emissions were from fertilizer use (80%), with minor emissions from fossil fuel combustion (19%), and waste combustion (1%).	None
Mississippi	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (99.5%), the majority of which is transportation petroleum. CO_2 emissions and sinks resulting from land use were estimated in this inventory, however, they are not included in this summary because Mississippi did not break out forest and land use changes by type of forest as described in the workbook methodology. Sources of CH_4 emissions included agricultural burning (43%), landfills (26%), domesticated animals (21%), manure management (7%), and rice cultivation (3%). N_2O emissions were accounted for by fertilizer use (95%) and agricultural burning (5%).	None
Missouri	Humid Continental (Hot Summer)/Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (97%), with minor emissions from cement and lime manufacturing. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 19% of the total CO_2 emissions. Sources of CH_4 emissions were domesticated animals (43%), manure management (28%), landfills (24%), natural gas production (4%) and fossil fuel combustion (1%). N_2O emissions were primarily attributable to fertilizer use (61%), fossil fuel combustion (28%), and nitric acid production (10%). Emissions of perfluorocarbons were entirely attributable to aluminum production.	PM-2.5 (1) Lead (1) 8-Hour O_3 (1)
Montana	Humid Continental (Warm Summer)	The major source of CO_2 emissions was fossil fuel combustion (99%), with minor emissions from cement manufacture and lime manufacture. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 54% of the total CO_2 emissions. Contributors to CH_4 emissions were domesticated animals (68%), landfills (22%), natural gas and oil production (7%), coal mining (3%), and wastewater (<1%). N_2O emissions were entirely attributable to fertilizer use. Emissions of perfluorocarbons were entirely attributable to aluminum production.	PM-10 (10) Lead (1) SO_2 (1) CO (1)
Nebraska	Humid Continental (Warm Summer)	N/A	None
Nevada	Desert/ Semiarid	The major source of CO_2 emissions was fossil fuel combustion (97%), with minor emissions from industrial processes (3%). Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 1% of the total CO_2 emissions. Contributors to CH_4 emissions included domesticated animals (50%), landfills (35%), natural gas processing, transmission, and distribution (9%), manure management (5%), and minor emissions from wastewater treatment and agricultural waste burning (1%). All N_2O emissions were accounted for by fertilizer use.	PM-10 (2) CO (2) 8-Hour O_3 (1)

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
New Hampshire	Humid Continental (Warm Summer)	The major source of CO_2 emissions was fossil fuel combustion (>99%) with minor emissions (<1%) from limestone used in agricultural soils and paper manufacturing; and soda ash used in paper manufacturing, glass and textile production, and water treatment. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 30% of the total CO_2 emissions. Contributors to CH4 emissions included landfills (84%), domesticated animals (8%), natural gas pipelines (3%), manure management (2%), fossil fuel combustion (2%), and wastewater treatment (<1%). N_2O emissions were accounted by fossil fuel combustion (97%) and fertilizer use (3%).	8-Hour O_3 (1)
New Jersey	Humid Continental (Hot Summer)	The only source of CO_2 emissions was fossil fuel combustion, with transportation petroleum accounting for about 50% of those emissions. Sources of CH_4 emissions were landfills (90%), natural gas and oil extraction (8%), domesticated animals (1%), wastewater (1%), and manure management (<1%). N_2O emissions were from nitric acid production (88%) and fertilizer use (12%). All sulfur hexafuoride emissions were from electric utilities. New Jersey did not evaluate sources and sinks (i.e., an increase in forest carbon storage) associated with land use.	PM-2.5 (2) 8-Hour O_3 (2)
New Mexico	Semiarid/ Desert	The major source of CO_2 emissions was fossil fuel combustion (more than 99%), with minor emissions from cement production. New Mexico generates a large amount of electricity, primarily from coal, for export to neighboring states. Thus, utility coal accounted for almost 50% of CO_2 emissions from fossil fuel combustion. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 7% of the total CO_2 emissions. Contributors to CH_4 emissions were natural gas and oil systems (48%), waste (22%), domesticated animals (19%), manure management (7%), and coal mining (4%). The source of N_2O emissions was fertilizer use.	PM-10 (1)
New York	Humid Continental (Hot Summer)	The major source of carbon dioxide emissions was fossil fuel combustion (99%), the majority of which is due to transportation petroleum. Minor emissions came from cement production (<1%). Carbon dioxide sources or sinks from forest resources were not estimated in this inventory. Sources of methane emissions were landfills (93%), domesticated animals (5%), fossil fuel combustion (1%), and manure management (<1%). Nitrous oxide emissions were accounted for by fossil fuel combustion (84%), and fertilizer use (16%).	8-Hour O_3 (8) PM-10 (1) PM-2.5 (1)
North Carolina	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (99%) with minor emissions (<1%) from lime processing, agricultural use of limestone, and waste combustion. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 8% of the total CO_2 emissions. Contributors to CH_4 emissions included manure management (49%), landfills (38%), domesticated animals (6%), fossil fuel combustion (5%), natural gas systems (1%), and agricultural burning (<1%). Nitrous oxide emissions were accounted for by fossil fuel combustion (54%), fertilizer use (46%), and agricultural burning (<1%).	PM-2.5 (2) 8-Hour O_3 (7)
North Dakota	Humid Continental (Warm Summer)	N/A	None
Ohio	Humid Continental (Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (99%), with minor emissions from cement production, lime manufacture and waste combustion. Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 2% of the total CO_2 emissions. Sources of CH_4 emissions were landfills (83%), coal mining (7%), domesticated animal (5%), manure management (3%), and agricultural residue burning (2%). Nitrous Oxide emissions were attributable to agricultural soil management (88%) and agricultural residue burning (12%). Emissions of CFCs were due to HCFC-22 production.	PM-2.5 (8) 8-Hour O_3 (11)

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Oklahoma	Semiarid/ Humid Subtropical	CO_2 accounted for the majority of Oklahoma's emissions; these emissions were primarily due to burning of fossil fuels for the production of electricity and, to a lesser extent, combustion for the transportation and industrial energy sectors. Other sources made minor contributions to CO_2 emissions. CH_4 was the next largest contributor, resulting from natural gas and oil systems, enteric fermentation, and manure management. N_2O, the third largest contributor, came chiefly from agricultural soil management. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) from industrial processes each made up a small share of the total emissions as well. The increase in HFC/PFC/SF6 emissions in 1999 was largely a result of the replacement of ozone-depleting substances (CFCs) with HFCs, which have high global warming potentials.	None
Oregon	Marine West Coast/Semiarid	The major source of CO_2 emissions was fossil fuel combustion (93%), with minor emissions from deforestation (6%), aluminum production (<1%), cement production (<1%), and lime production (<1%). Contributors to CH_4 emissions were landfills (47%), domesticated animals (38%), manure management (9%), natural gas production (6%), and burning of agricultural waste (<1%). Nitrous oxide emissions were accounted for by fertilizer use, and perfluorocarbon emissions were accounted for by aluminum production.	PM-10 (5) CO (1)
Pennsylvania	Humid Continental (Hot Summer)	The majority of Pennsylvania's emissions came from CO_2, with the burning of fossil fuels constituting most of the CO_2 emissions in both years. The largest end-use categories for fossil fuel combustion were electricity production, transportation, and industrial uses. CH_4 was the next largest contributor, mostly from coal mining, oil, and natural gas systems, and the anaerobic decay of solid waste in landfills. N_2O came chiefly from manure management and the burning of fossil fuels. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) were emitted from a number of industrial processes. The doubling of HFC/PFC/SF6 emissions in 1999 was largely a result of the replacement of ozone-depleting substances (CFCs) with HFCs, which have high global warming potentials.	PM-2.5 (8) SO_2 (2) 8-Hour O_3 (17)
Rhode Island	Humid Continental (Hot Summer)	The only reported source of CO_2 emissions was fossil fuel combustion. Sources of CH_4 emissions were landfills (80%), wastewater treatment (7%), domesticated animals (6%), fossil fuel combustion (6%), and manure management (1%). N_2O emissions were primarily attributable to fossil fuel combustion (92%), wastewater treatment (6%), and agricultural soils (2%).	8-Hour O_3 (1)
South Carolina	Humid Subtropical	N/A	8-Hour O_3 (3)
South Dakota	Humid Continental (Warm Summer)	N/A	None
Tennessee	Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (97%), the majority of which is utility coal. CO_2 sinks (i.e., an increase in forest carbon storage) offset about 4% of the total CO_2 emissions. Sources of CH_4 emissions were landfills (51%), domesticated animals (27%), coal mining and natural gas production (11%) and manure management (10%). N_2O emissions were attributable to fertilizer use and agricultural crop wastes.	PM-2.5 (2) 8-Hour O_3 (6)
Texas	Semiarid/ Desert/ Humid Subtropical	The majority of CO_2 emissions were from fossil fuel combustion (96%), with the remainder due to land-use change and forestry (3%) and cement manufacture (1%). Sources of CH_4 emissions were landfills (36%), domesticated animals (31%), oil and gas systems (26%), manure management (5%), rice cultivation (2%), and coal mining (<1%). N_2O emissions were attributable to acid production (51%), agricultural soil management (45%), and manure management (4%).	PM-10 (1) CO (1) 8-Hour O_3 (4)

States	Climate Type	Major Sources of Greenhouse Gas	Types and Number of Nonattainment Areas
Utah	Semiarid/ Desert	The major source of CO_2 emissions was fossil fuel combustion (97%), with minor emissions from cement and lime production and limestone use. Sources of CH_4 emissions were coal mining (51%), domesticated animals (21%), natural gas/oil extraction (15%), and landfills (13%). N_2O emissions were attributable to nitric acid production (72%) and fertilizer use (28%).	PM-10 (3) SO_2 (2)
Vermont	Humid Continental (Warm Summer)	The only source of carbon dioxide emissions was fossil fuel combustion, the majority of which is due to transportation petroleum. Carbon dioxide sinks (i.e., an increase in forest carbon storage) offset about 1.3% of the total carbon dioxide emissions. Sources of methane emissions were domesticated animals (65%), landfills (33%) and manure management (1.3%). Nitrous oxide emissions were attributable to fertilizer use.	None
Virginia	Humid Continental (Hot Summer)/ Humid Subtropical	The major source of CO_2 emissions was fossil fuel combustion (99%). CO_2 sinks (i.e., an increase in forest carbon storage) offset about 16% of the total CO_2 emissions. Contributors to CH_4 emissions were landfills (70%), coal mining (21%), manure management (5%), and domesticated animals (4%). Nearly all N_2O emissions were accounted for by fertilizer use (93%), with minor emissions from agricultural burning.	8-Hour O_3 (5) PM-10 (1)
Washington	Marine West Coast/Semiarid	The major source of CO_2 emissions was fossil fuel combustion (99%), with minor emissions from lime manufacture, aluminum production, and cement production. Carbon dioxide sinks (i.e., increases in forest carbon stocks) offset about 25% of the total CO_2 emissions. Contributors to CH_4 emissions were landfills (66%), domesticated animals (19%), manure management (11%), coal mining (2%), and burning of agricultural waste (1%). Nitrous oxide emissions were accounted for by fertilizer use (97%), and the burning of agricultural waste (3%). All perfluorocarbons were emitted from aluminum production.	None
West Virginia	Humid Continental (Hot Summer)	CO_2 accounted for the majority of West Virginia's emissions. These emissions were mostly due to the burning of fossil fuels, primarily for the production of electricity. CH_4 was the next largest contributor, mostly from coal mining. N_2O, the third largest contributor, came chiefly from agricultural soil management and fossil fuel combustion. Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6), all of which resulted from industrial processes, each made up a small share of the total emissions as well.	PM-2.5 (5) PM-10 (2) SO_2 (1) 8-Hour O_3 (6)
Wisconsin	Humid Continental (Warm Summer/Hot Summer)	The major source of CO_2 emissions was fossil fuel combustion (99%). CO_2 sinks resulting from land use were not estimated in this inventory. Contributors to CH_4 emissions were domesticated animals (55%), landfills (22%), coal mining (8%), natural gas production (9%), manure management (6%), and fossil fuel combustion (1%). N_2O emissions were attributable to agricultural soils (63%), fossil fuel combustion (35%), and waste combustion (2%).	8-Hour O_3 (5)
Wyoming	Semiarid/ Unclassified Mountainous	N/A	PM-10 (1)

Note: (1) Sources reported by the most recently published State GHG Emissions and Sinks Inventory summaries.

NA = Not Available

Source: Encarta, 2005d; EPA, 2005a; EPA, 2006a.

3.3 GEOLOGIC RESOURCES

The following section describes geologic resources on a nationwide basis that may be affected by sequestration projects, including potential CO_2 capture and storage field validation projects and activities associated with MM&V and research efforts.

3.3.1 Definition of Geologic Resources

Within a given physiographic province, geologic resources typically are described by the geology, soils, groundwater, geologic hazards, and mineral resources of the area, as defined below.

- Geology - The rock types and structures that form the Earth's crust.
- Soils - Unconsolidated materials above the bedrock.
- Groundwater - Water in the zone of saturation below the water table.
- Geologic hazards - A geologic condition or phenomenon that presents a risk or is a potential danger to life and property, either naturally occurring (e.g., earthquakes, volcanic eruptions) or man-made (e.g., ground subsidence).
- Mineral Resources - The presence, distribution, quantity, and quality of mineral resources that are of economic value (e.g., oil, natural gas, coal, and others).

3.3.2 Overview of Geologic Resources in the U.S.

3.3.2.1 Geology Overview

Although the science of geology involves the study of many components that comprise the Earth, from plate tectonics to mineral composition, this discussion will use the term geology to refer to the rock types that are present in a particular area. There are three rock types that comprise the rock cycle, igneous, sedimentary, and metamorphic, as described below.

- Igneous rocks are formed by the solidification and crystallization of cooling magma (i.e., molten rock material). Magmas form at depth below the ground surface and the molten material may or may not reach the surface of the Earth before it cools and solidifies. Examples of igneous rocks include granite (cooled slowly while still buried below the surface) and basalt (magma that reaches the surface before cooling). All igneous rocks are crystalline in some form and generally there is little pore space that can be occupied by fluids, including water. Most igneous rocks are structurally strong until fractured or weathered.

- Sedimentary rocks are formed when sediments (loose, unconsolidated mineral or rock particles that have been transported by wind, water, or ice, and re-deposited) are compacted or cemented together into a solid rock. Sedimentary rocks are formed at or near the Earth's surface and are generally more compact than the original sediments. Types of sedimentary rocks include sandstone (cemented sand-sized particles), shale (compacted very fine-grained materials), and limestone (formed by precipitation from solution, composed mostly of calcite). Generally, fluids can travel through sedimentary rocks at varying rates depending on the degree of cementation and the material that makes up the sedimentary rock. For example, moderately cemented sandstone can transmit water (aquifer) while an intact shale unit will prohibit the flow of water (aquitard). Many sedimentary rocks are not structurally strong unless the rock exhibits extensive cementation.

- Metamorphic rocks are formed from other, preexisting rocks that are subjected to very high temperatures and/or pressures. High temperatures can cause re-crystallization or the development of new minerals, and pressure can deform the rock. These changes occur while the rock is still solid. Any type of preexisting rock can be metamorphosed, and examples include marble (metamorphosed limestone), quartzite (metamorphosed quartz-rich sandstone), and slate (metamorphosed shale that develops foliation under the applied stress). The ability of a metamorphic rock to transmit a fluid and the strength of the rock are dependent on the origin of the both the preexisting rock and the stress applied. Generally, a metamorphic rock behaves similarly to an igneous rock.

The U.S. can be subdivided into distinct geomorphic provinces that share a common geologic character and history (Section 3.3.3). These provinces are important since many geologic formations could serve as potential sinks, or places where carbon can be placed and prevented from reaching the atmosphere. When CO_2 is sequestered in a geologic formation, the mineral resources in and adjacent to the formation would no longer be available to be extracted.

3.3.2.2 Soils Overview

Soils are dynamic ecosystems composed of a combination of minerals, organic matter, and living organisms. The variety of soil types is the result of the diversity of minerals and organisms that compose them. Soils consist of four main types: sand, silt, clay, and loam. Sandy soils have a coarse texture; clay soils have a sticky texture; and silt particles, which are smaller than sand particles but larger than clay, give soils a silky, powdery texture. Loam soils, which are the best for agriculture, consist of sand, silt, and clay. Mineral and organic particles make up about 50 percent of soil volume; pores containing air and water make up most of the remaining volume.

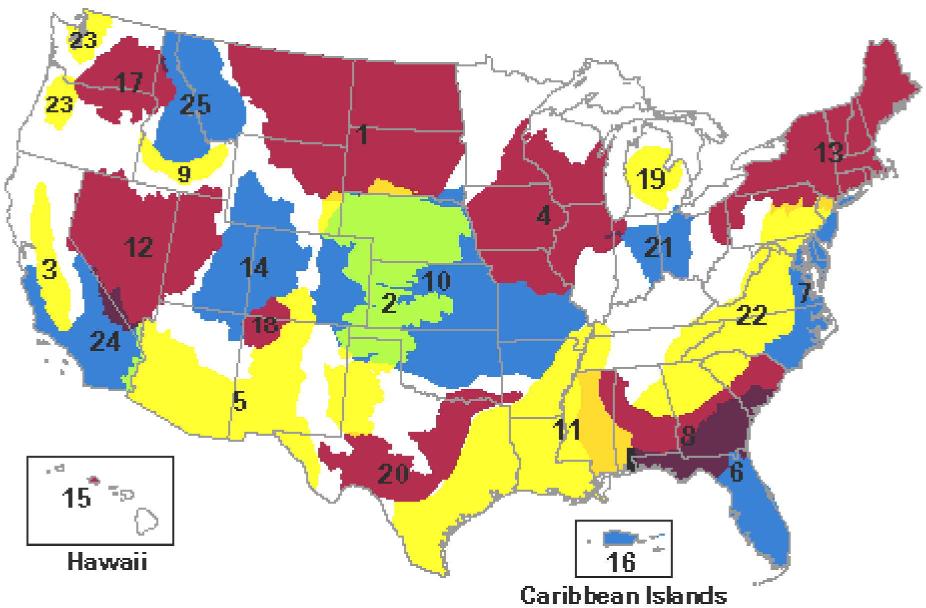
Soils form continuously, but very slowly, through the weathering of rocks by wind and rain. In addition to minerals from the weathering of rocks, soils contain organic matter, called humus, from the decomposition of plants and animals. As soils form over time, layers build up, called horizons, which have different characteristics and composition.

3.3.2.3 Groundwater Overview

Groundwater is part of the hydrologic cycle that lies beneath the water table. Groundwater aquifers, or porous subterranean regions saturated with groundwater, underlie most of the land in the U.S. Large volumes of usable groundwater exist within these aquifers. Figure 3-10 depicts some of the major regional aquifer systems in the U.S. For example, the High Plains aquifer (also called the Ogallala Aquifer) underlying the midwestern U.S. is thought to contain almost a quadrillion gallons of water (Figure 3-11). Approximately 50 percent of the population in the U.S. derives a portion of its freshwater from groundwater sources, and more than a third of the water used in agriculture practices is obtained from groundwater aquifers.

Carbon sequestration activities are focused on storage in deep saline formations. (Discussed in 3.3.5.3).When CO_2 is injected into a formation, there is a potential for the CO_2 gas to escape into shallower formations, cause contamination of usable groundwater, or create other adverse effects. It is possible to minimize these potential adverse impacts through careful site selection, detailed hydrogeologic characterization, and subsurface hydraulic testing to verify the subsurface reservoir is favorable for long-term isolation of the fluids. Understanding the site-specific geologic conditions and limitations are important to ensure that only suitable locations for geologic sequestration are proposed. Moreover, it is crucial to comply with relevant UIC regulations and to employ BMPs for injection well construction, operation and monitoring. Potential impacts to geologic resources are further described in Chapter 4.

Between 1950 and 1995, annual groundwater withdrawal increased 150 percent in the U.S. Some aquifers are recharged regularly by rainfall or from surface water sources; however, the current rate of groundwater extraction exceeds long-term recharge rates in many basins (USGS, 2000b). Depletion of groundwater in storage increases the costs of extraction and may induce water quality degradation, land subsidence, and eventually loss of the resource. Several areas in the U.S. currently experiencing significant groundwater depletions include parts of the west and midwest, the lower Mississippi Valley, sections of the southeast including Florida, the Chicago-Milwaukee area, and eastern Washington. Additionally, groundwater mining is a growing concern for the High Plains Aquifer that underlies parts of Colorado, Kansas, Oklahoma, Nebraska, New Mexico, South Dakota, Texas and Wyoming where groundwater withdrawals account for 96 percent of all groundwater withdrawals nationally (Levin et al., 2002; USGS, 1999).



Regional Aquifer Systems in the United States	
1 Northern Great Plains	14 Upper Colorado River basin
2 High Plains	15 Oahu, Hawaii
3 Central Valley, California	16 Caribbean Islands
4 Northern Midwest	17 Columbia Plateau
5 Southwest Alluvial Basins	18 San Juan Basin
6 Floridian	19 Michigan Basin
7 Northern Atlantic Coastal Plain	20 Edwards-Trinity
8 Southeastern Coastal Plain	21 Midwestern Basins and Arches
9 Snake River Plain	22 Appalachian Valleys and Piedmont
10 Central Midwest	23 Puget-Willamette Lowland
11 Gulf Coastal Plains	24 Southern California Alluvial Basins
12 Great Basin	25 Northern Rocky Mountain Intermontane
13 Northeast Glacial Aquifers	

Note: This map is from one USGS study and does not represent all regional aquifers in the U.S.

Source: USGS, 2000b.

Figure 3-10. Regional Aquifer Systems in the United States

Groundwater protection occurs at the Federal, State, and local government levels through various agencies. Environmental, agricultural, and natural resource agencies regulate groundwater extraction and preservation through laws, regulations, and policies. The EPA has designated approximately 75 sole source aquifers nationwide. This designation is intended to protect drinking water supplies in areas with few or no alternative water resources. The EPA must review any project within a sole source aquifer designated area that will be receiving federal financial assistance. A summary of the sole source aquifers in the U.S. is provided in Table 3-4 (EPA, 2005).

Table 3-4. Sole Source Aquifers in the United States

EPA Region	Sole Source Aquifer Name	State(s)
I	Pootatuck Aquifer	CT
	Cape Cod Aquifer	MA
	Nantucket Island Aquifer	
	Martha's Vineyard Aquifer	
	Head of Neponset Aquifer System	
	Plymouth-Carver Aquifer	
	Canoe River Aquifer	
	Broad Brook Basin of the Barnes	
	Monhegan Island	ME
	Vinalhaven Island Aquifer System	
	North Haven Island Aquifer System	
	Isleboro Island Aquifer System	
	Block Island Aquifer	RI
	Hunt-Annaquatucket Pettaquamscutt	
	Pawcatuck Basin Aquifer System	RI, CT
II	Buried Valley Aquifers, Central Basin, Essex and Morris Counties	NJ
	Upper Rockaway River Basin	
	Ridgewood Area Aquifers	
	Highlands Aquifer System- Passaic, Morris & Essex Cos. NJ; Orange Co. NY	NJ, NY
	NJ Fifteen Basin Aquifers	
	Ramapo River Basin Aquifer Systems	
	NJ Coastal Plain Aquifer System	NJ, DE, PA
	Nassau/Suffolk Co., Long Island	NY
	Kings/Queens Counties	
	Schenectady/Niskayuna	
	Clinton Street-Ballpark Valley Aquifer System, Broome and Tioga Cos.	
	Cattaraugus Creek Basin Aquifer, WY & Allegany Cos.	
	Cortland-Homer-Preble Aquifer System	
III	Maryland Piedmont Aquifer – Montgomery, Howard, Carroll Cos.	MD
	Poolesville Area Aquifer Extension of the Maryland Piedmont Aquifer	
	Seven Valleys Aquifer, York County	PA
	Prospect Hill Aquifer, Clark County	VA
	Columbia and Yorktown, Eastover Multi-aquifer System – Accomack, N. Hampton	
IV	Biscayne Aquifer, Broward, Dade, Monroe & Palm Beach Cos.	FL
	Volusia-Floridan Aquifer, Flagler & Putnam Cos.	
	Southern Hills Regional Aquifer System	LA/MS
V	St. Joseph Aquifer System	IN
	Mille Lacs Aquifer	MN
	Pleasant City Aquifer	OH
	Bass Island Aquifer, Catawba Island	
	Miami Valley Buried Aquifer	
	OKI extension of the Miami Buried Valley Aquifer	
	Allan County Area Combined Aquifer System	

EPA Region	Sole Source Aquifer Name	State(s)
VI	Chicot Aquifer System	LA
	Arbuckle-Simpson Aquifer, South Central Oklahoma	OK
	Edwards Aquifer, San Antonio Area	TX
	Edwards Aquifer, Austin Area	TX
VII	None	--
VIII	Missoula Valley Aquifer	MT
	Castle Valley Aquifer System	UT
	Western Unita Arch Paleozoic Aquifer System at Oakley, UT	
	Glen Canyon Aquifer System	
	Eastern Snake River Plain Aquifer Stream Flow Source Area	WY
	Elk Mountain Aquifer	
IX	Upper Santa Cruz & Avra Basin Aquifer	AZ
	Bisbee-Naco Aquifer	
	Fresno County Aquifer	CA
	Santa Margarita Aquifer, Scotts Valley	
	Campo/Cottonwood Creek	
	Ocotillo-Coyote Wells Aquifer	
	Northern Guam Aquifer System	GU
	Southern Oahu Basal Aquifer	HI
	Molokai Aquifer	
X	Eastern Snake River Plain Aquifer	ID, WY
	North Florence-Dunal Aquifer	OR
	Spokane Valley Rathdrum Prairie Aquifer	WA, ID
	Lewiston Basin Aquifer	
	Camano Island Aquifer	WA
	Whidbey Island Aquifer	
	Cross Valley Aquifer	
	Newberg Area Aquifer	
	Cedar Valley (Renton Aquifer)	
	Central Pierce Cty. Aquifer System	
	Marrowstone Island Aquifer System	
	Vashon-Maury Island Aquifer System	
	Guemes Island Aquifer System	

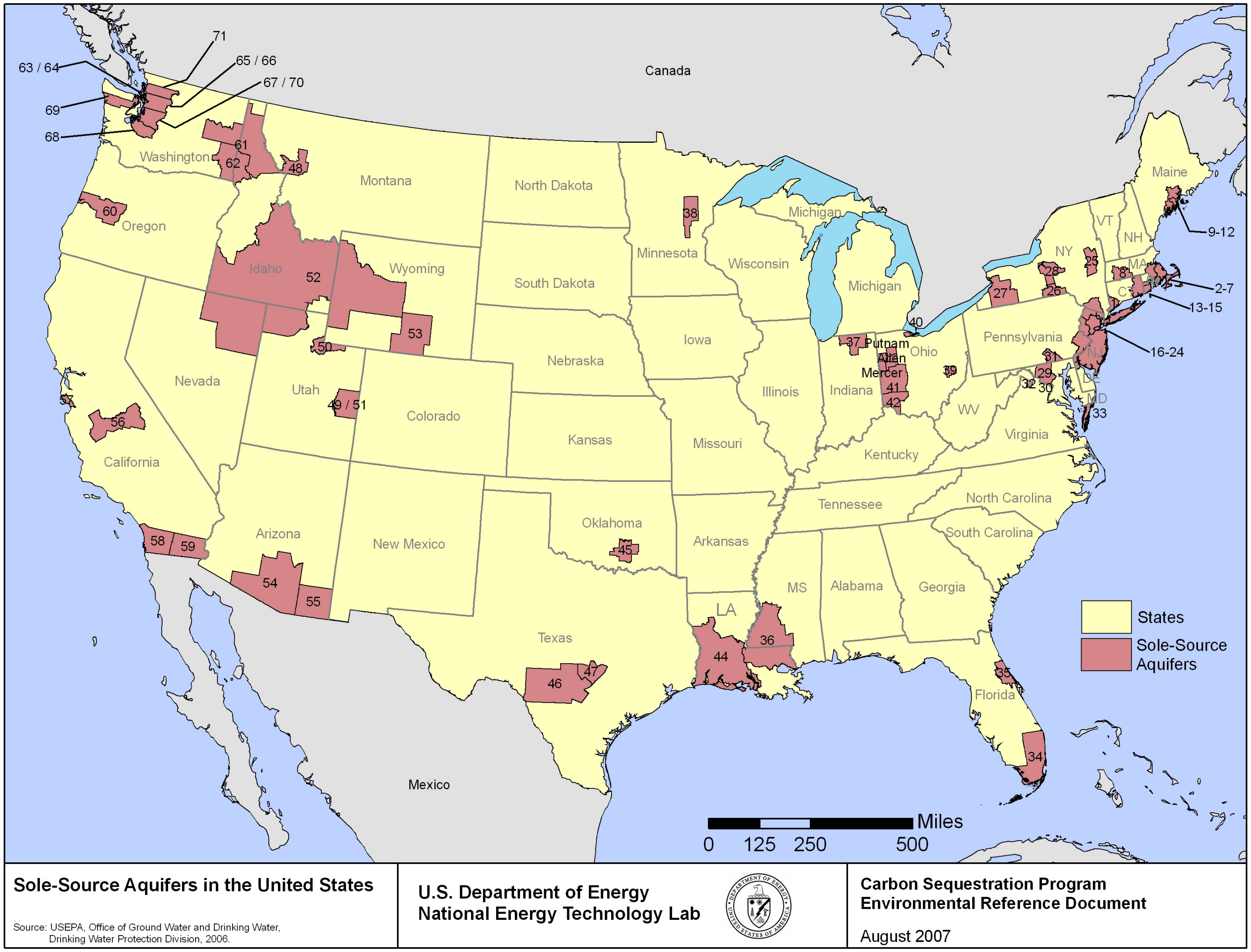


Figure 3-11. Sole-Source Aquifers in the U.S.

3.3.2.4 Hazards Overview

Geologic hazards could be caused, triggered or exacerbated by potential sequestration activities. Knowledge of the location of geologic hazards will therefore be integrated into the site selection process for future sequestration projects.

Geologic hazards are present in various forms (e.g., volcanoes, earthquakes, landslides, subsidence, etc.) throughout the U.S., and these hazards can potentially cause both harm to human health and safety and property damage. Although geologic hazards exist and can be exacerbated by human activities (e.g., deep injection wells), knowledge of the location of hazards will be integrated into the selection process for the location of future sequestration projects. By design, therefore, project locations will be selected to avoid areas of extreme hazards. This section discusses the geologic hazards that could be caused, triggered, or exacerbated by the potential sequestration activities.

An earthquake may be caused by deformation of rocks in the Earth's crust. Typically earthquakes are attributable to a sudden rupture of the rocks adjacent to a geologic structure, such as an active fault, due to excessive build up in the tectonic stress in that area. In addition to severe shaking of the ground surface, large earthquakes may cause other damaging effects to the environment, such as surface fracturing, landslides, liquefaction, tsunamis, and seiches. Some earthquakes appear to have been triggered in regions of elevated tectonic stress by anthropogenic activities such as deep well injection or filling of large surface reservoirs.

The areas of greatest seismic activity in the U.S. generally tend to be along the western rim of North America and where the boundaries of Missouri, Arkansas, Tennessee, Kentucky, and Illinois converge (USGS, 2005b). The latter is the New Madrid Seismic Zone (also known as the Reelfoot Rift or the New Madrid Fault Line). Between 1974 and 2003, Alaska had 12,053, or 57.2 percent, of all U.S. earthquakes. Alaska was followed by California (4,895, 23.2 percent), Hawaii (1,533, 7.3 percent), Nevada (778, 3.7 percent), Washington (424, 2.0 percent), Idaho (404, 1.9 percent), and Wyoming (217, 1.0 percent). Other top-15 earthquake states (with less than one percent of the U.S. earthquakes) are in descending order, Montana, Utah, Oregon, New Mexico, Arkansas, Arizona, Colorado, and Tennessee. Figure 3-12 depicts seismic hazard areas in terms of peak acceleration and probability.

Landslides are widespread in areas of steep topography with high relief. Annually, landslides cause approximately $2 billion in damages and an average of more than 25 fatalities. Landslides occur in all 50 states and are common throughout the Appalachian and New England Regions, but also occur across the Interior Plains and into the mountain areas of the western U.S.

Land subsidence is a gradual settling or sudden sinking of the ground surface. In the U.S., more than 17,000 square miles in 45 states have been directly affected by subsidence. The principal causes for subsidence are aquifer-system compaction, drainage of organic soils, underground mining, hydro-compaction, natural compaction, sinkholes, and thawing permafrost.

Geologic hazards can become more likely when some types of projects are conducted. For example, when gases or liquid are injected into the subsurface via injection wells, there is a potential for increased seismic activity or earthquakes, depending on the geologic conditions. Therefore, it will be important to review the potential for geologic hazards at the future site of any sequestration project in order to avoid adverse impacts to other resources that may be caused if the sequestration process (including long-term storage) triggers or exacerbates natural geologic hazards at the site.

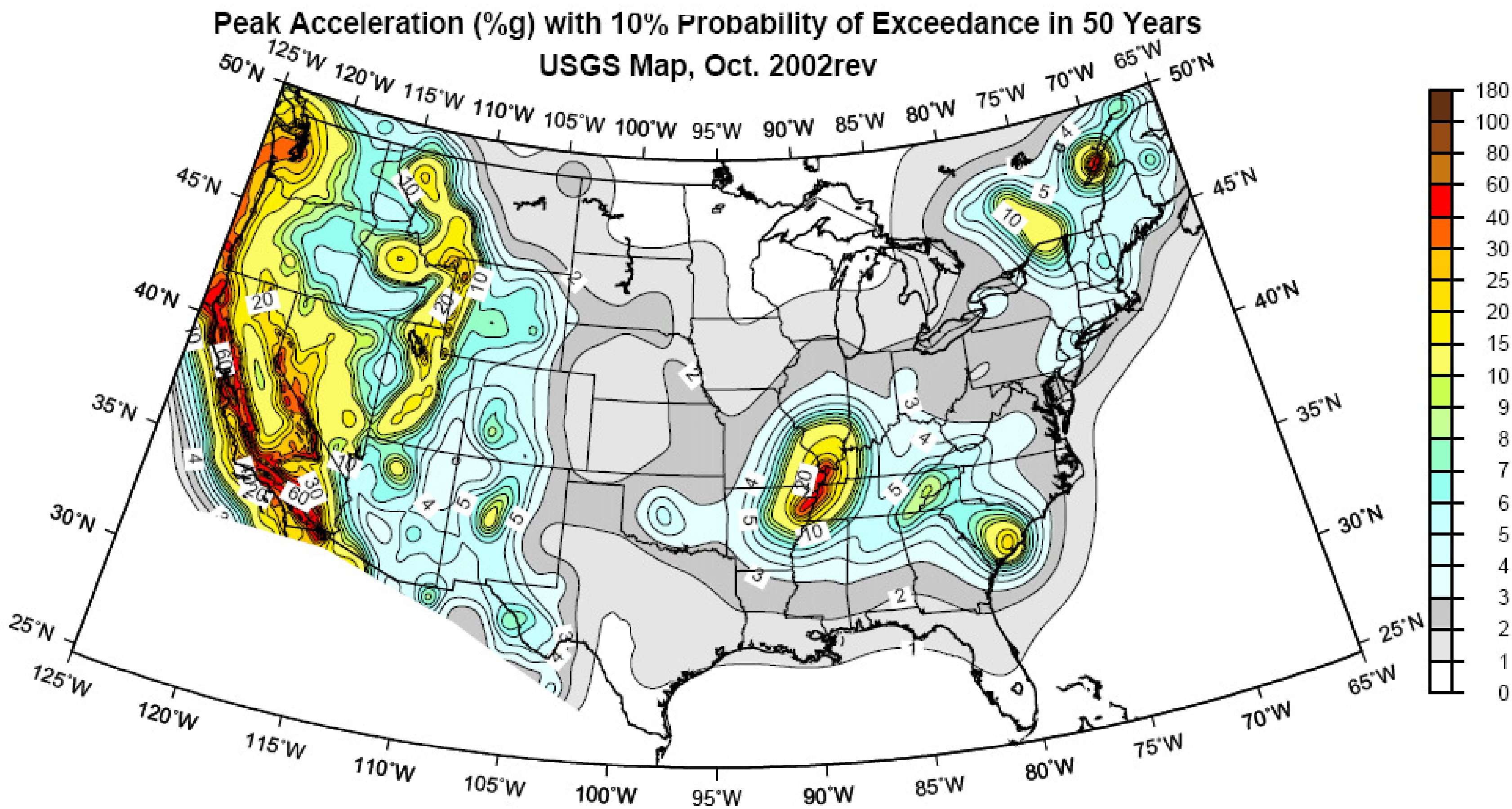
3.3.2.5 Mineral Resources Overview

Various mineral resources can be found throughout the U.S., including coal deposits, oil and gas reservoirs, and other mineral deposits. As several of the proposed geologic sequestration technologies are directly related the distribution of coal seams and oil and gas reservoirs, these mineral resources are discussed below.

Approximately 1,071 million short tons of coal are produced from the regions shown in Figure 3-13 The coal in these regions varies in rank from anthracite to sub-bituminous as shown in Figure 3-14 and Figure 3-15.

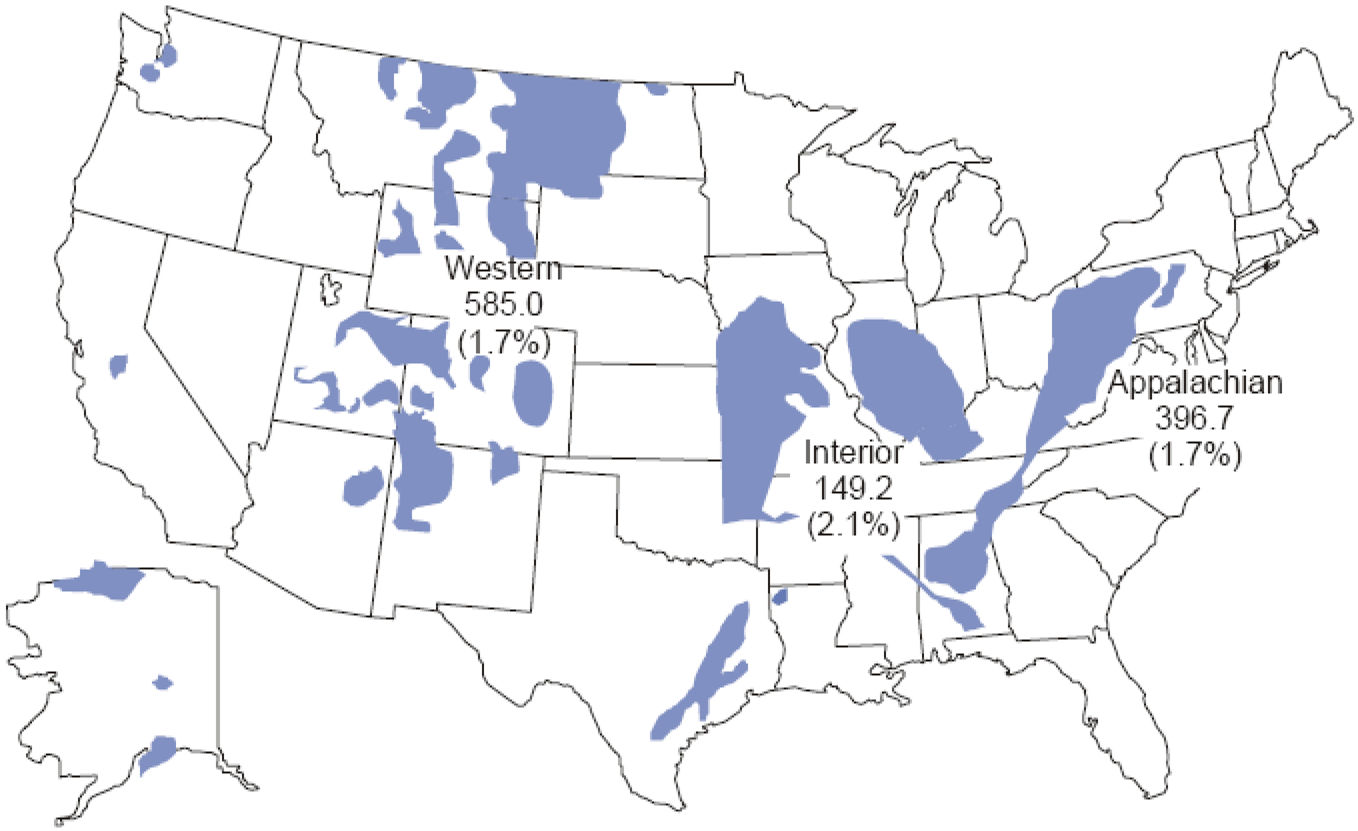
According to the EIA, there were 21,891 million barrels of crude oil proved reserves as of December 31, 2003 (EIA, 2005a). The majority of crude oil discoveries in 2003 were new fields in the Gulf of Mexico Federal Offshore reserves. Since 1977, crude oil reserves have been primarily sustained by expansion of the proven reserves in existing fields rather than the discovery of new oil fields. Oil and gas basins of the U.S. are shown in Figure 3-16 and Figure 3-17 (USGS, 2005a). Oil and gas resources in the U.S. are shown in Figure 3-18 and Figure 3-19.

As of December 31, 2003, the EIA also indicated there were 189,044 billion cubic feet of dry gas reserves in the U.S (EIA, 2005b). Production declines in the Gulf of Mexico, New Mexico, and Louisiana were offset by production increases in Colorado, Texas, Oklahoma, and Wyoming. Coal-bed methane proved reserves were 18,743 billion cubic feet in 2003, accounting for 10 percent of U.S. dry gas proved reserves. The potential for future development of CBM resources is indicated in Figure 3-20. Alaska has the highest predicted CBM future resources, followed by the Powder River Basin in Wyoming and Montana, the Northern Appalachian Basin in West Virginia, Ohio, and Pennsylvania, and the San Juan Basin in Colorado and New Mexico (USGS, 2005a).



Source: USGS, 2003.

Figure 3-12. Seismic Hazard Map of the U.S.



Source: EIA, 2005c.

Figure 3-13. Coal Production in the U.S. in 2005

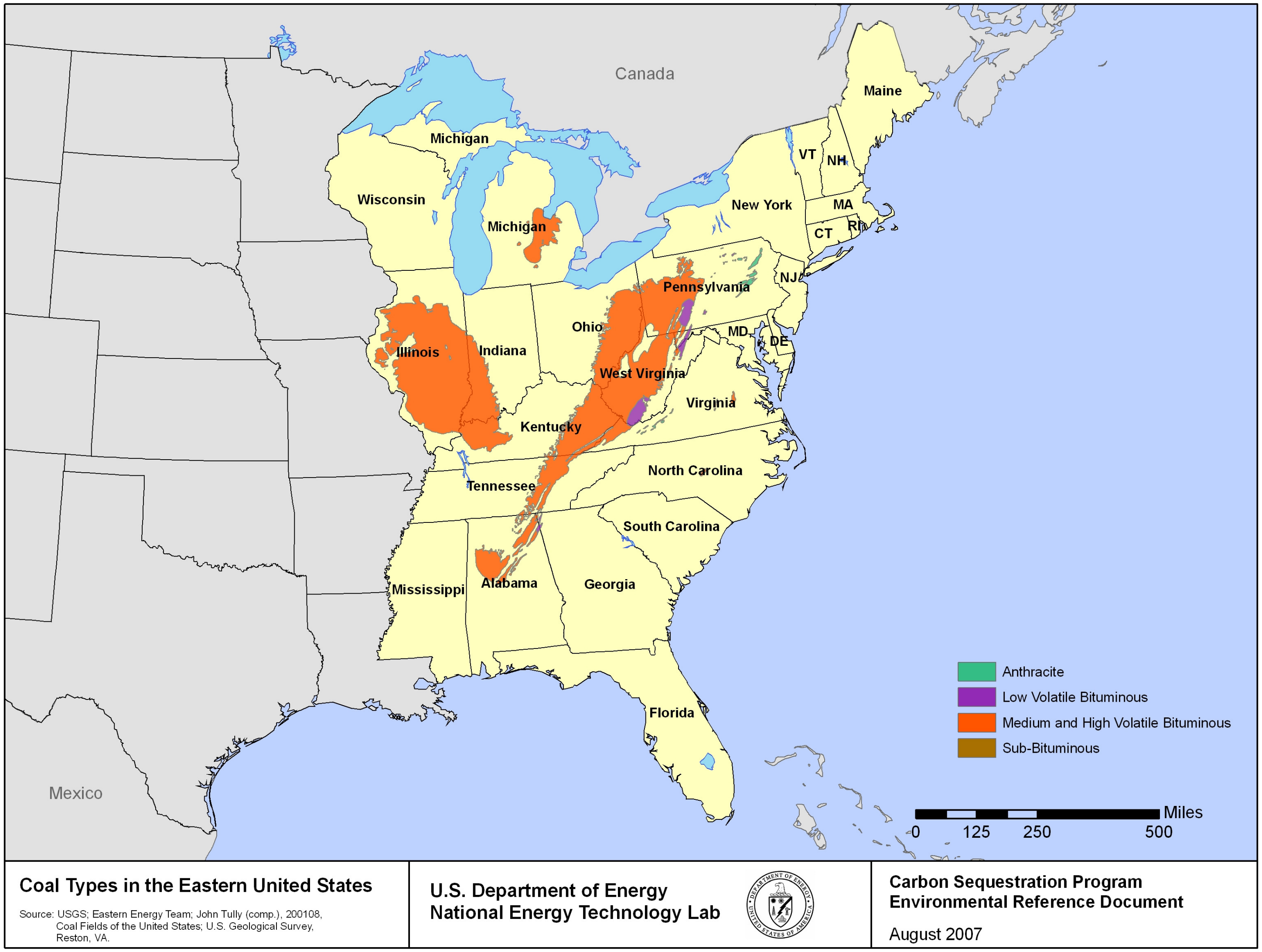
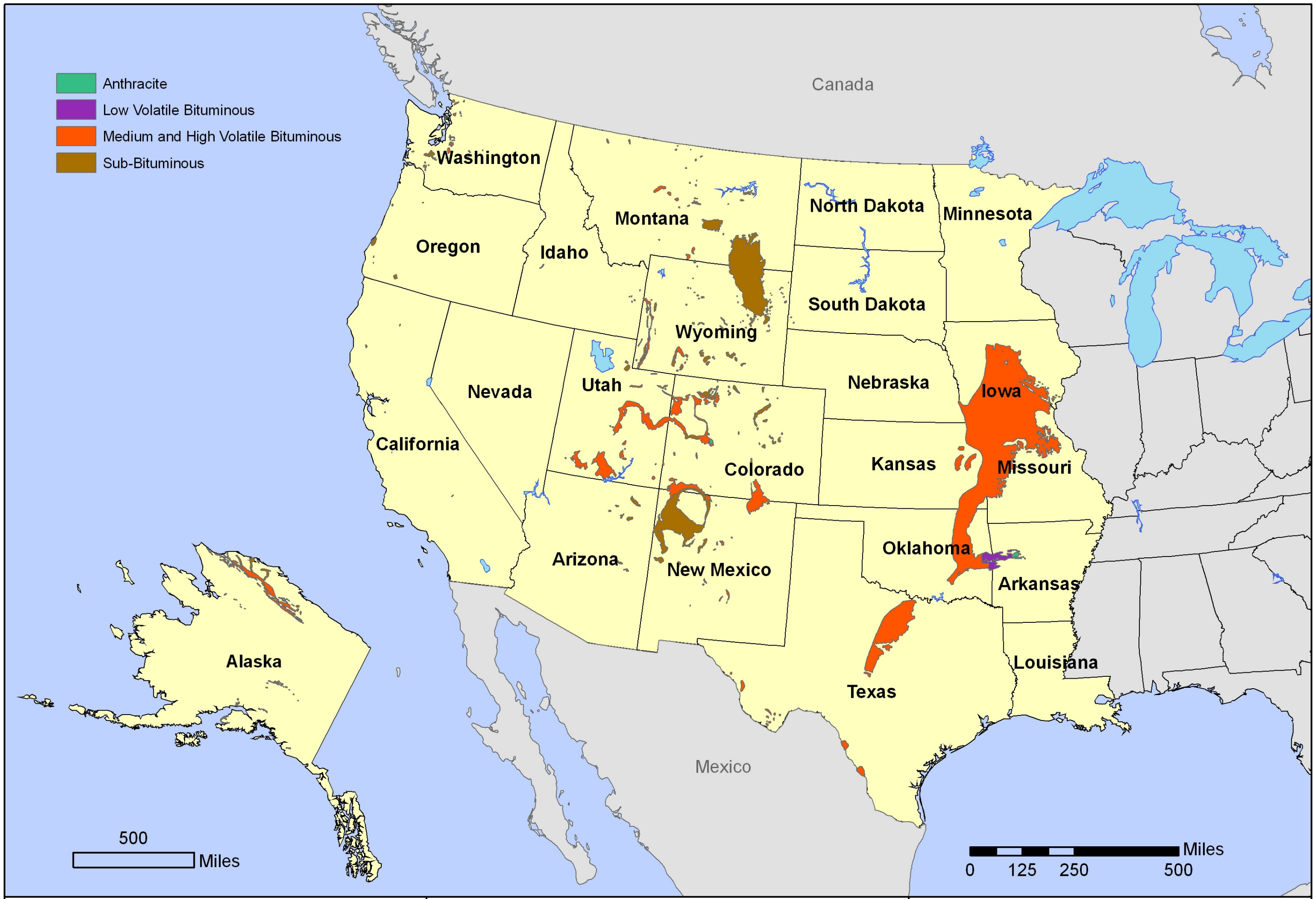


Figure 3-14. Coal Types - East



Coal Types in the Western United States

Source: USGS; Eastern Energy Team; John Tully (comp.), 200108, Coal Fields of the United States; U.S. Geological Survey, Reston, VA.

U.S. Department of Energy
National Energy Technology Lab

Carbon Sequestration Program
Environmental Reference Document

August 2007

Figure 3-15. Coal Types - West

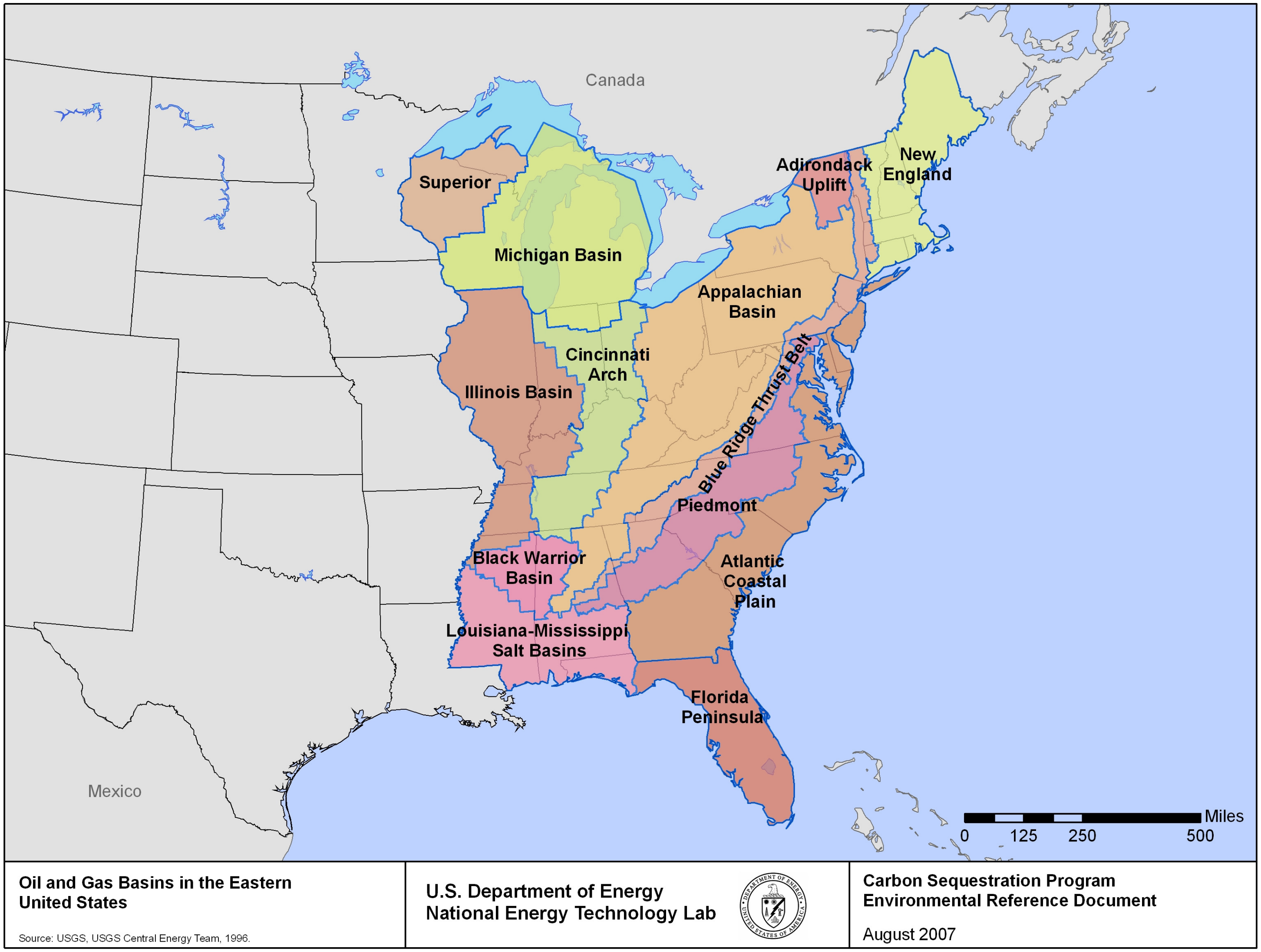


Figure 3-16. Oil and Gas Basins - East

Oil and Gas Basins in the Western United States

Source: USGS, USGS Central Energy Team, 1996.

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National Energy Technology Lab

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Figure 3-17. Oil and Gas Basins - West

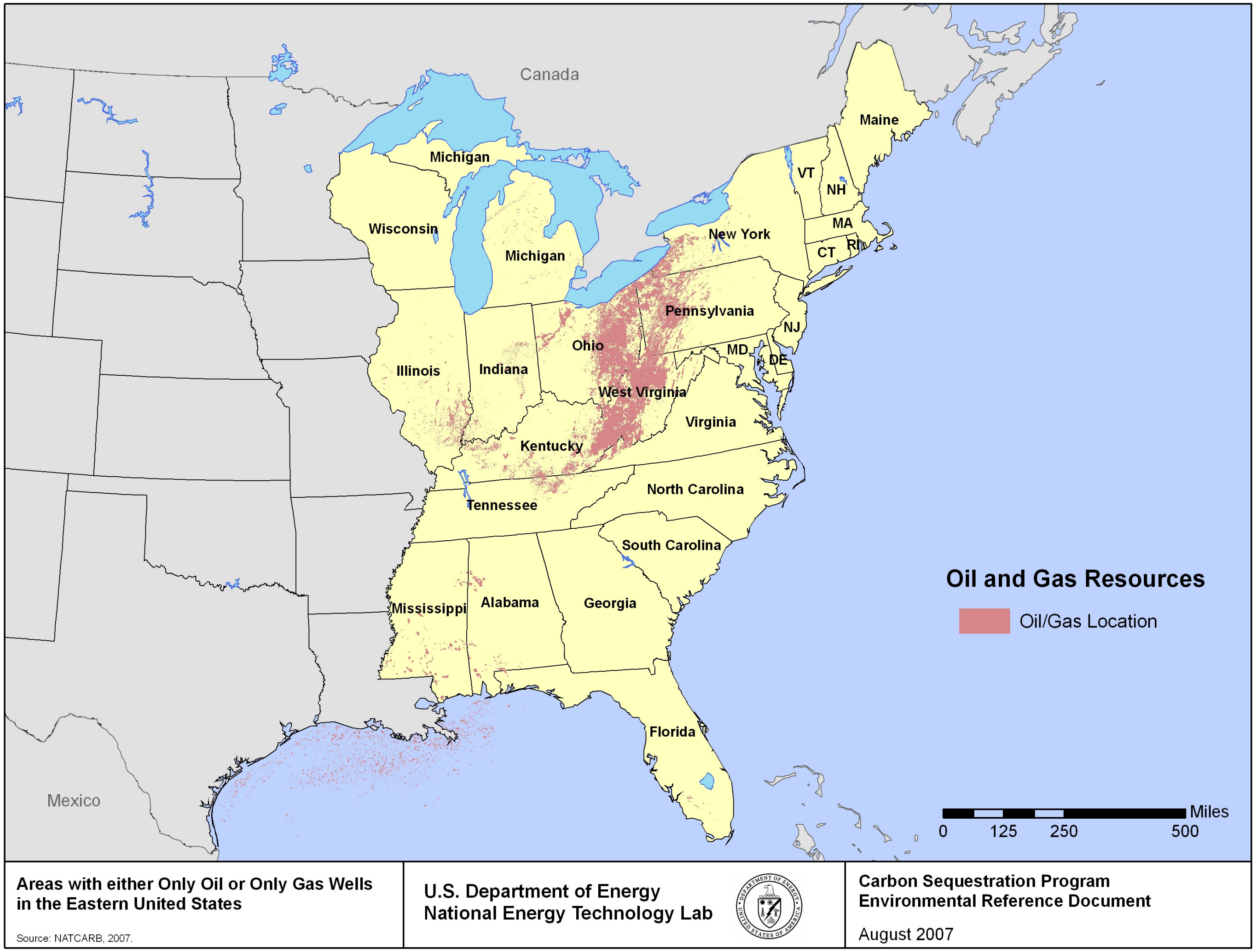

Figure 3-18. Oil and Gas Wells - East

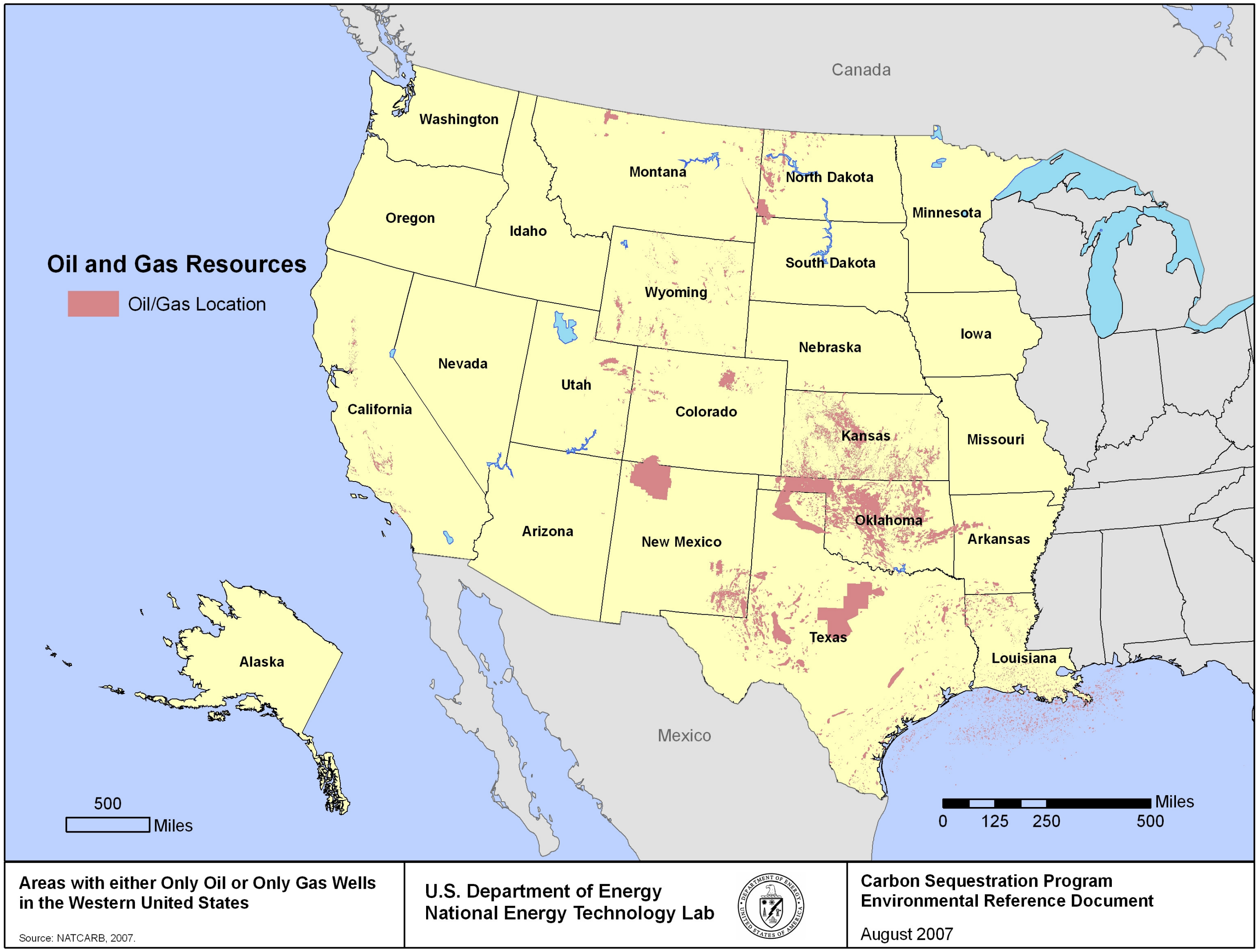

Figure 3-19. Oil and Gas Wells - West

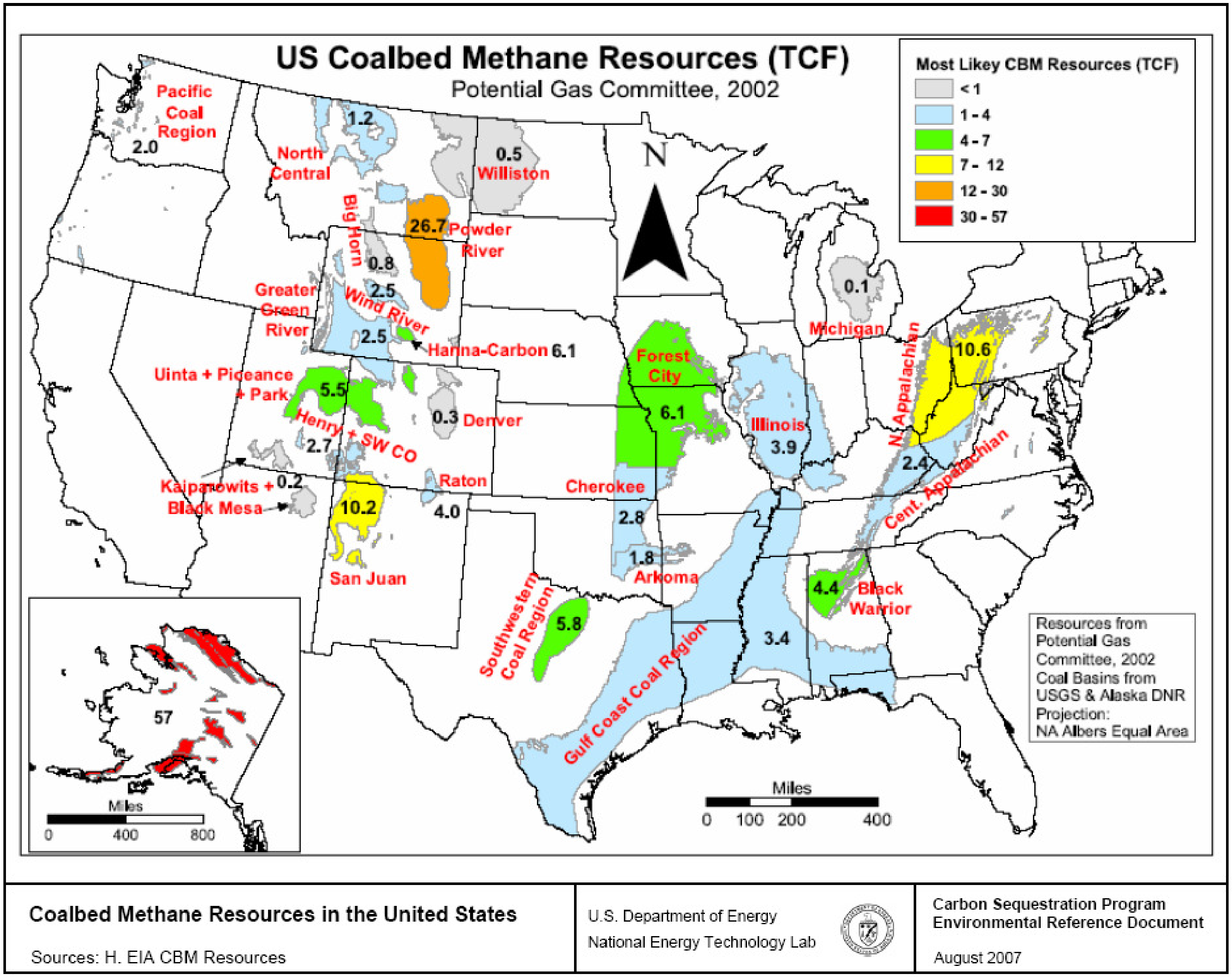

Figure 3-20. Coal Bed Methane

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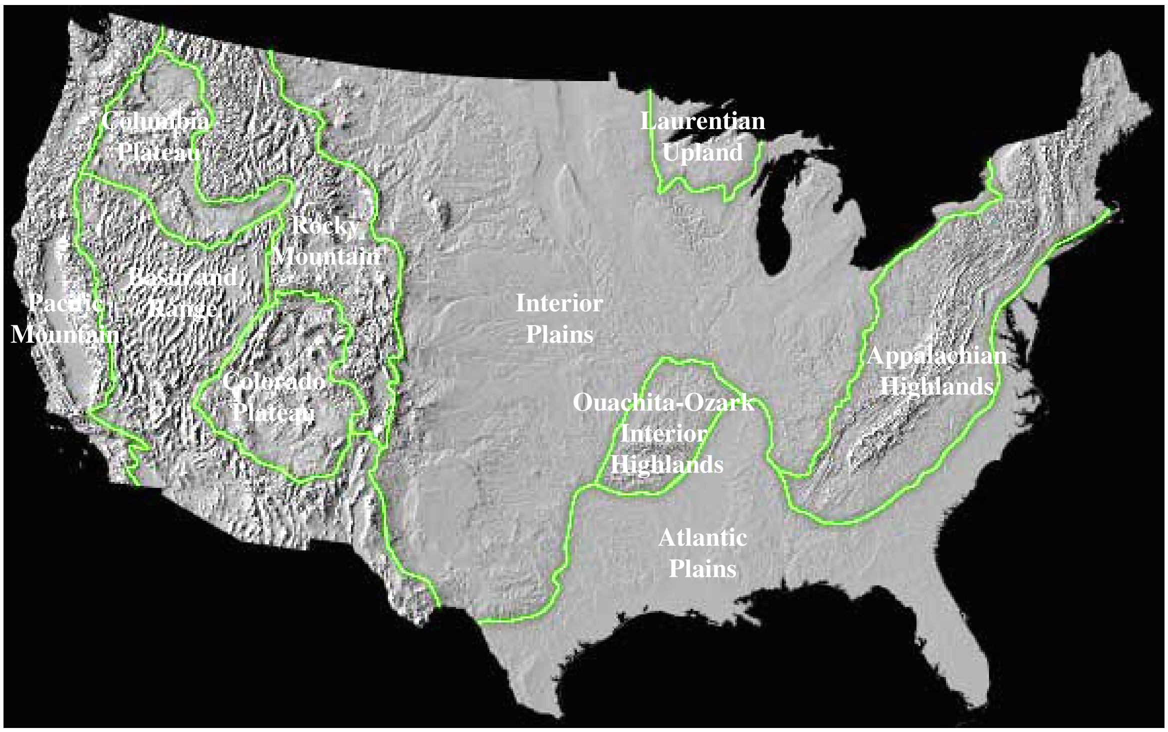
3.3.3 Geologic Provinces

As mentioned in the national overview of geology (Section 3.3.2.1), the U.S. can be subdivided into distinct geologic provinces having similar physiographic features and geologic characteristics. While as many as 25 geologic provinces have been recognized in the lower 48 states, the major divisions illustrated on Figure 3-22 are used to provide a summary description of the geologic features (USGS, 2000a).



Source: USGS, 2000a.

Figure 3-21. Geologic Provinces of the United States

3.3.3.1 Appalachian Highlands Province

The Appalachian Highlands Province is characterized by the Appalachian Mountain Range, which reveals elongated belts of folded marine sedimentary rocks, volcanic rocks, and slivers of ancient ocean floor. The ridges of the mountains are erosion-resistant sandstone, while the valleys are comprised of limestone and other less-resistant rock layers. Some molten rock in the Appalachian Highlands cooled very slowly and formed coarse-grained veins called pegmatites, which have been the source of high-purity minerals (such as feldspar, quartz, and mica) and gemstones (such as emeralds and beryl). Other minerals that can be found in the Appalachian Highlands include coal, iron ore (hematite), zinc, marble and slate. The Appalachian Basin is one of the most important coal-producing regions in the U.S. and the world. Historic and recent production records show that about 34.5 billion short tons of coal have been produced in this region.

3.3.3.2 Laurentian Upland Province

The Laurentian Upland Province area is part of the nucleus of North America referred to as the Canadian Shield. The bedrock in this region is composed predominantly of Precambrian igneous and metamorphic rocks. Large portions of this area were overlain by Paleozoic sedimentary rocks that were subsequently eroded to expose underlying Precambrian rock units. Substantial copper deposits were discovered in the Precambrian rocks on the Keweenaw Peninsula of northern Michigan during the latter half of the last century.

3.3.3.3 Atlantic Plain Province

The Atlantic Plain Province is characterized by the flattest topography of the provinces. It stretches over 2,200 miles in length from Cape Cod to the Mexican border and southward another 1,000 miles to the Yucatan Peninsula. The Atlantic Plain slopes gently seaward from the inland highlands in a series of terraces. This gentle slope continues far into the Atlantic Ocean and Gulf of Mexico, forming the continental shelf. Historically, sediments eroded from the Appalachian Mountains and other inland highlands were carried east and southward by streams and gradually covered the land, burying it under thousands of feet of layered sedimentary and volcanic debris. Today, the sedimentary rock layers that lie beneath much of the coastal plain and fringing continental shelf remain nearly horizontal. Mineral resources found in the Atlantic Plain Province include petroleum and natural gas, phosphate, uranium, salt, sulfur, heavy minerals sands, and clays.

3.3.3.4 Ouachita-Ozark Interior Highlands Province

The ancient, eroded mountains of the Ouachita-Ozark Highlands stand surrounded by the nearly flat-lying sedimentary rocks and deposits of the Interior and Atlantic Plains Provinces. In the Ouachita Mountains, folds and faults now contort these ancient marine rocks. The rocks closely match deformed strata found today in the Marathon Mountains of Texas and the southern Appalachians. Mineral resources produced in the province include limestone, quartzite, sand and gravel, asphaltite, lead, and oil and gas.

3.3.3.5 Interior Plains Province

The Interior Plains Province is a vast region that spreads across the craton of North America. Precambrian metamorphic and igneous rocks now form the basement of the Interior Plains and are the stable nucleus of North America. With the exception of the Black Hills of South Dakota, the entire region has low relief, reflecting more than 500 million years of relative tectonic stability. Sediments eroding from the rising Rocky Mountains to the west washed into the ancient Sundance Sea and were deposited as layered wedges of fine debris. Preserved within the multi-hued sandstones, mudstones, and clays that made up the shoreline are the remains of countless dinosaurs that roamed the Sundance coast.

3.3.3.6 Rocky Mountain Province

The Rocky Mountain Province took shape during a period of intense plate tectonic activity that formed much of the rugged landscape of the western U.S. Deep basins that contain sediment shed from the mountains by erosion separate individual mountain ranges. These basins are often the source of oil and gas deposits.

3.3.3.7 Colorado Plateau Province

The Colorado Plateau Province encompasses a vast region of plateaus, mesas, and deep canyons and is characterized by nearly horizontal layers of sedimentary rock that have been deeply dissected by stream erosion, especially by the Colorado River. Thick layers of limestone, sandstone, siltstone, and shale were laid down in the shallow marine waters. One of the most geologically intriguing features of the Colorado

Plateau is its remarkable stability. Relatively little rock deformation (faulting and folding) has affected this high, thick crustal block within the last 600 million years or so. In contrast, provinces that have suffered severe deformation surround the plateau.

3.3.3.8 Basin and Range Province

The Basin and Range Province is characterized by a multitude of down-dropped valleys and elongated mountains. Basins filled with geologically young sedimentary rocks separate the ranges. Basalt flows also exist in some of these basins. Except for its relatively large amount of structural deformation and tectonic activity, this province is generally similar in geology to the Colorado Plateau Province.

3.3.3.9 Pacific Mountain Province

The Pacific Mountain Province is one of the most geologically young and tectonically active provinces in North America, and the landscape of this province provides evidence of ongoing mountain building. The Sierra Nevada mountain range is composed of mostly granitic rocks while the Cascade mountain range is made up of a band of thousands of very small, short-lived volcanoes.

3.3.3.10 Columbia Plateau Province

The Columbia Plateau Province includes one of the world’s largest accumulations of lava. Over 170,000 cubic kilometers of basaltic lava, known as the Columbia River basalts, covers the western part of the province.

3.3.3.11 Pacific Mountain Province

In relation to the rest of the geology of North America, the Pacific Mountain Province is one of the youngest and most tectonically active provinces. The landscape of the province shows evidence of continuing mountain formation. The Sierra Nevada mountain range is composed of mostly granitic rocks while the Cascade mountain range is made up of a band of thousands of very small, short-lived volcanoes.

3.3.4 Summary of Geologic Resources Potentially Affected by Carbon Sequestration Technologies

There are three main components to the sequestration projects described in this section, capture of CO_2, geologic sequestration of CO_2, and MM&V of the project site before, during, and after sequestration. Each of these components has the potential to affect the geologic resources of the project area, and these effects are discussed in a general manner in the following text. A more detailed discussion for the various geologic sequestration technologies is included in Section 3.3.5 (CAN Europe, 2003a; Espie, 2004; Geotimes, 2003; NETL, 2005).

3.3.4.1 Post-Combustion Capture

The geologic resources affected by the capture of CO_2 are mainly limited to the capture location (e.g., at the power plants, oil refineries, or industrial sites) (CAN Europe, 2003b). The facilities that are constructed, the associated industrial processes, and the resulting potential for environmental releases could affect the geologic resources of an area; however, these effects would be site-specific, directly associated with the capture technology utilized, and dependent on the industrial CO_2 source.

Although the geologic resources of an area will need to be addressed on a site-by-site basis in future environmental documents, a few generalizations can be made for the potential effects of CO_2 capture on the geology, soils, and groundwater of a project area, including the following:

- Construction of CO_2 capture facilities could disturb the soils of an area.
- Any release or spill of materials involved in the capture of the CO_2 could affect the natural geology, soils, and groundwater quality.
- The capture of CO_2 may increase water consumption.
- An increase in water consumption for the capture process could also cause a proportional increase in the amount of wastewater that requires treatment or disposal.

3.3.4.2 Geologic Sequestration

Various geologic formations could be utilized to sequester the captured CO_2, including depleted oil reservoirs, unmineable coal seams, saline formations, and other formations as determined on a site-specific basis (Figure 1-10). The geologic resources of an area affected by geologic CO_2 sequestration technologies would be associated with the construction and operation of facilities, industrial processes, potential for environmental releases of materials, wastes, or chemicals, and reaction of the geologic formation to the addition of CO_2. Geologic resources that may be affected by applying these technologies include the following.

3.3.4.2.1 Geology

- The injection of CO_2 into a formation could potentially alter the natural geomorphology and activate a fault or fracture. In an extreme case the alteration might trigger a seismic event.
- The physical characteristics and current land use/resources located in an outcrop area of the geologic formation used for sequestration may be affected by leakage from sequestration activities. For example, if the formation outcrop is proximal to the injection location for sequestration in unmineable coal seams, CO_2 leakage may migrate up-dip in the coal seam or overlying formation and vent to the atmosphere where these outcrops daylight. Discharge of CO_2 from the outcrop may have adverse impacts to biological resources.
- The sequestration processes could cause undesirable migration of natural chemical constituents (e.g., heavy metals).

3.3.4.2.2 Soils

- The soils in the area of the sequestration site could be impacted if there is a spill or CO_2 leakage on site. The volume of soil impacted would depend on the size of the CO_2 plume and the migration pathway.
- The sequestration processes could stimulate the mobilization of heavy metals found in the soils.

3.3.4.2.3 Groundwater

- The natural water quality of the area could be impacted due to the sequestration processes.
- As a result of a sequestration project, potable water supplies could become contaminated due to several processes, which include migration of CO_2 after injection, leakage of formation fluids, or mobilization of chemical constituents (e.g., crude oil, CH_4 gas, metals, organic constituents, or brine water) from the host formation into overlying aquifers.
- The addition of CO_2 to a formation may decrease the natural pH of the formation water slightly. Co-sequestration of H_2S with the CO_2 may cause an even more substantial lowering of pH.

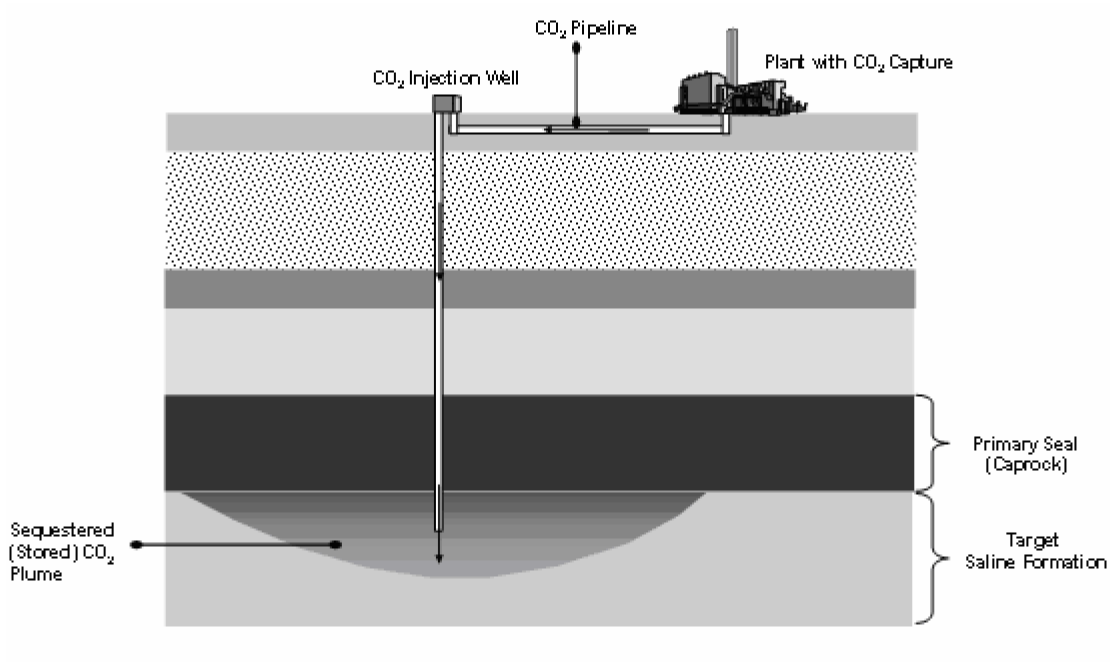


Figure 3-22. Geologic Formations and Sequestration

- Changes in formation pressure water pH could increase dissolved concentrations of natural elements present in the formation, and induce the dissolution of limestone formations, if present. Increasing the acidity of the formation water would also likely increase corrodibility and cause more rapid deterioration of well casings and equipment.
- The sequestration technologies could increase the need for water to use in operation and production processes. Additionally, there could be an increase in the amount of water that would need to be disposed of in a treatment or municipal system.

3.3.4.3 Monitoring, Mitigation, and Verification

The technologies associated with MM&V of CO_2 sequestration will vary based on the site, capture and sequestration processes utilized, and surrounding environment. MM&V will be utilized to verify the success of the capture technologies, determine the short- and long-term effectiveness of the sequestration operation, quantify any leak rates, and assess the influence of the technology on the surrounding environment. The geologic resources of an area may be affected by the facilities and equipment needed to implement MM&V efforts, including the use of chemicals, solvents, or dyes, and any wastes produced. Water resources, water quality, and the natural soil geochemistry may be affected by spills or leakage of these products. The use of geologic and groundwater models will help determine the success of the sequestration, as well as provide a basis for the refinement of processes.

Some of the MM&V technologies that can be utilized at a sequestration site include the following:

- Subsurface geophysics;
- High precision land surveying to detect changes in land surface due to the change in pressure at depth from the injection of CO_2 ;
- Fluid sampling (surface water, groundwater, etc.);

- Air sampling, especially near any potential leakage pathways like existing oil and gas production wells;
- Tracers to track the movement of the stored CO_2;
- CO_2 flux towers;
- Well pressure monitoring.

3.3.5 Geologic Resources Potentially Affected by Geologic Sequestration Technologies

Currently, the majority of the CO_2 sequestration projects and research initiatives are focused on geologic sequestration technologies. There are three main targets for geologic sequestration including unmineable coal seams, oil and gas reserves, and saline water-bearing formations. Although other breakthrough technologies are being studied, these three viable alternatives are being implemented on both large and small scales at several project sites, as discussed below. These projects allow for the collection of actual - not theoretical or laboratory-based - data regarding the injection, migration, and interaction of the emplaced CO_2 in the various geologic formations. These data will clarify the components of a sequestration process and site characteristics that are essential to the successful implementation of the technology at multiple, varied sites at a full-scale production level.

In addition to studying the currently operating geologic sequestration projects, empirical data can also be collected from natural settings. High-purity CO_2 is produced by natural process and is geologically sequestered in formations, generally in sedimentary basins. These stable storage systems for CO_2 can be studied to obtain long-term data, and the site characteristics and interaction of the CO_2 with the surrounding environment can be used to generalize site selection criteria and clarify sequestration project operational issues.

Experts have estimated that geologic sequestration technologies could account for the disposal of hundreds to thousands of gigatons of carbon in the future (Herzog and Golomb, 2004). Validation of the technologies is underway and is aided by the various proven injection technologies currently used in industry. The projects described in the following sections account for only a small portion of the current research; however, characteristics of these projects can be used to generalize the site conditions necessary for successful geologic sequestration of CO_2 and the geologic resources that could be affected by the realization of the technologies.

3.3.5.1 Coal Seam Sequestration

There are 6 main coal producing regions in the U.S: Northern Rocky Mountains and Great Plains, Colorado Plateau, Illinois Basin, Gulf Coast, Appalachian Basin, and Alaska. Within each of these regions, there are various types of coal present, and there are areas of either abandoned underground coal mines or coal seams that are uneconomical to mine due to the location, depth, or coal grade.

Coal seam sequestration of CO_2 utilizes the same natural mechanisms that trap the naturally formed hydrocarbon gases, mainly CH_4, in the coal. The gases are adsorbed (i.e., attached by chemical attraction) to the coal in the micropores or trapped in the macropore space. These mechanisms allow the coal to store a much larger amount of gas than a comparable volume in an oil reserve due to the amount of surface area available for the adsorption. The process is analogous to the use of activated carbon filters to remove contaminants from a water supply.

The surface of the coal has a preferred affinity for adsorption of CO_2 over CH_4 at an approximate ratio between 2:1 and 3:1. Therefore, when the CO_2 is injected into the target coal seam, it displaces the CH_4, which can be recovered and sold to offset the cost of the sequestration project. This process is referred to as ECBM recovery. The amount of natural gas available in a coal seam is dependent on the rank of the coal, which is measured by the carbon content. ECBM is an important component of the sequestration technology from a financial, operational, and environmental standpoint.

For a coal seam to be suitable for CO_2 sequestration, it needs to be not only unmineable due to economic or physical restrictions, but the seam should have a high transmissivity or permeability, high effective porosity, and high storativity, among other characteristics to be described. In many cases, unmineable coal seams have low permeability, making it difficult to inject the CO_2 and extract the CH_4. Additionally, the adsorption of the CO_2 onto the coal surface can cause the coal to swell, further reducing the permeability of the seam and limiting injection and extraction. These limitations for site selection and the relationship between the required coal characteristics and the surrounding geologic resources are discussed in the following text.

3.3.5.1.1 Example Coal Seam Sequestration Project – San Juan Basin, Colorado and New Mexico

The San Juan Basin in southern Colorado and northern New Mexico is one of North America's largest natural gas fields and has been in production for approximately 75 years. Additionally, the basin contains methane-bearing coal seams that have proven to be highly productive. The basin is approximately 200 miles long from north to south and 130 miles wide from east to west, and contains geologic units ranging in age from the Cambrian to Quaternary. The formations of interest for this study are from the Upper Cretaceous time period and consist of the coal-bearing Fruitland Formation and the overlying Kirtland Shale Unit, as further described below. There are two current sequestration projects in the San Juan Basin, the Tiffany Unit CBM Project (Tiffany) and the Allison Unit Project (Allison) (BLM, 1996). Both of these sites are part of the DOE research project called "Coal-Seq" designed to study various aspects of the sequestration process (Reeves and Oudinot, 2004; Reeves et al., 2003).

At Tiffany, which is operated by BP America, N_2 has been injected to enhance the recovery of CH_4 from the Fruitland Formation since 1998; however, injection was suspended in 2002 to evaluate the results. Injecting N_2 lowers the partial pressure of the CH_4, which enables the extraction. Tiffany is the largest and longest running N_2-ECBM site in the world. Allison, operated by Burlington Resources, began injecting CO_2 in 1995 and was the first CO_2-ECBM project. Injection was suspended in 2001 to evaluate results of the study to date. The CO_2 is supplied by a natural reservoir located in the Cortez area of New Mexico (i.e., no post-combustion capture technologies are being utilized). Prior to the injection of CO_2, depressurization was used for approximately 6 years to recover CH_4 from the coal seams in the area. The combination of studying both the Tiffany and Allison units in this basin allows for conclusions to be drawn regarding the injection of post-combustion gas for ECBM because both CO_2 and N_2 are present in flue gas (Reeves and Oudinot, 2004; Reeves et al., 2003).

3.3.5.1.2 Geology in the Area of the Tiffany and Allison Units

Tiffany produces from 4 Upper Cretaceous Fruitland Formation coal seams. The average depth to the top of the shallowest coal seams is approximately 3,040 feet. The coal is classified as medium volatile bituminous and the initial temperature and pressure are recorded as 120°F and 1,600 psi, respectively. The coal has a gentle dip to the north-northeast where the units thicken slightly. The maximum permeability of the coals was determined to be on a northwest-southeast orientation, aligned with the face-cleat, and the anisotropy was estimated to be about 2.4. The average intrinsic permeability (i.e., a function of the size of the openings through which fluid moves) was determined to be 1.6 millidarcy and the average porosity was 0.8 percent (Reeves and Oudinot, 2004).

Allison also produces from three Upper Cretaceous Fruitland Formation coal seams with an average depth to the top of the shallowest seam of about 3,100 feet. The initial pressure and temperature were recorded as 1,650 psi and 120°F. The CO_2 is injected at approximately 1,500 psi (reduced from transport pressure of about 2,200 psi) and is heated prior to injection to prevent the expansion and contraction of the well during periods of no injection. The coals have a gentle dip towards the south-southwest, where the seams thicken slightly. Porosity ranges from 0.3 percent in the southwest of the project area to 0.05 percent in the northwest. Research at Allison has indicated that the absolute intrinsic permeability of the coal (ranging from 30 to 150 millidarcy) is about twice the effective permeability to gas (Reeves et al., 2003).

The Kirtland Shale overlies the Fruitland Formation, and based on the structure of the basin and the relative age of the formations, both the Fruitland and Kirtland outcrop within the basin boundaries. The Tiffany site is approximately 12 miles from the nearest Fruitland Formation outcrop. The thickness of the Fruitland Formation varies between 0 and 500 ft while the Kirtland Shale reaches a maximum thickness of approximately 1,500 ft. The Lower Kirtland Shale interval (approximately 450 ft maximum thickness in the study area) represents the caprock for the target formation. This shale unit has extremely low permeability and is aerially extensive (BLM, 1996).

3.3.5.1.3 Soils in the Area of the Tiffany and Allison Units

The typical soils in the study area are deep loams to silty-clay loams on nearly level to steep slopes. The soils have a moderate to high potential for erosion, low salinity, and moderate pH. Erosion can occur when the protective plant cover is removed for construction and transport purposes. Rainfall can then wash the topsoil to local waterways, and the increased sediment load to the waterway can increase downstream sediment deposition. Soils located on moderate to steep slopes are particularly susceptible to water erosion; however, the Tiffany and Allison sites are located in an area with generally gentle topographic relief (BLM, 1996).

3.3.5.1.4 Groundwater in the Area of the Tiffany and Allison Units

The San Juan Basin is a structural depression spanning portions of New Mexico and Colorado. Based on this structural formation and the relative location of geologic units, the Fruitland Formation is under confined groundwater conditions in the center of the basin extending to within approximately 2 miles of the outcrop. Groundwater resources for the area typically are drawn from the shallow aquifers on alluvial and terrace deposits and from sandstone aquifers in the San Jose and Animas Formations, both stratigraphically located above the Kirtland Shale Unit. These aquifers are used for both domestic and livestock/agricultural purposes, and wells can yield up to 75 gpm. In the area of the Tiffany and Allison projects, the Fruitland Formation groundwater is too deep and of too poor quality to be utilized as a water supply, and shallow, potable aquifers are isolated from the production and injection intervals by the Kirtland Shale Unit (BLM, 1996).

3.3.5.1.5 Geologic Hazards in Area of Tiffany and Allison Units

Geologic hazards in the project areas are limited. The depth of the production coal seams and the consolidated nature of the seams preclude subsidence. Landslides are not a factor as the site is located in an area of low topographic relief. Localized faulting and fracturing have occurred, especially along the margins of the San Juan Basin. However, within the central portion of the basin, in the study area, there are very few faults or fractures present. Although localized structures occur along the margins of the basin, these features do not result in a substantial hydraulic connection between overlying formations and the Fruitland Formation (BLM, 1996).

3.3.5.1.6 Preliminary Results at the Tiffany and Allison Units

Preliminary conclusions drawn from the work completed at Allison indicate that the physical processes of CO_2 sequestration are working because measurements of CO_2 concentration at the wells have been low. However, significant permeability and injectivity losses occurred with increasing CO_2 injection. Therefore, only a limited volume of CO_2 could be emplaced in the coal seams (Reeves et al., 2003).

The adsorption rate of the CO_2 onto the coal is dependent upon the temperature and pressure of the injection interval, which are functions of the depth of the interval. Additionally, the coal type affects adsorption of the CO_2. These site limitations should be added to any conceptual model created to evaluate a site for the sequestration of CO_2 in coal seams (Reeves and Oudinot, 2004).

3.3.5.1.7 Application of Coal Seam Sequestration in Other Locations

To better understand the geologic resources that may be affected by CO_2 sequestration in coal seams, it will be important to continue the testing and monitoring at the Tiffany and Allison units sites, as well as study other projects. For example, two other projects are the CONSOL Energy site in the northern panhandle of West Virginia and the RECOPOL site in the Silesian Coal Basin of Poland.

Coal seam sequestration is possible throughout the Appalachian, Interior and Western Coal Regions (Illinois, Northern Appalachian, Central Appalachian, Michigan Basins, Gulf Coast, Southwestern, Arkoma, Forest City, Black Warrior Basins, Cherokee, Powder River, Big Horn, Wind River, Hanna-Carbon, Greater Green River, Denver, Henry, SW CO, Raton, San Juan, Black Mesa, Kajpanowits, Uinta, Piceance, Williston, North Central, and Park Basins). Refer to Figure 3-13 for the coal regions and Figure 3-20 for the coal basins (as part of the coalbed methane resources) noted below. A summary of geologic site conditions necessary for successful coal seam sequestration is also discussed below.

Although the geologic resources in the potential locations of coal seam sequestration sites listed above can vary greatly, several generalizations can be made that provide some initial site selection characteristics. These characteristics were determined to be essential to minimize the effect of the sequestration activities on the geologic resources of an area.

- The target coal seams would be deep, thick, and inter-bedded with permeable sandstone strata. The seams would have high transmissivity, high effective porosity, and high storage capability.
- The coal seams would be hydrogeologically isolated from any potable aquifer (e.g., thick and laterally continuous, low permeability unit between the target coal seam and any potable water supply).
- Faults and fractures would be minimal in the project area, and any structures occurring in the area would not transmit water vertically between geologic units. No significant geologic hazards should exist in the project area.
- The coal seams would either be laterally confined to prevent potential migration of injected CO_2 (the portion of CO_2 that is not adsorbed onto the coal), or the target injection location would be laterally far away from any geologic outcrop of the coal seam (as groundwater levels decrease, the gases in the coal could be liberated at the outcrop of the coal seam).
- The sequestration site would be located near the CO_2 source to minimize the effects of the CO_2 transportation on the area.

3.3.5.2 Sequestration in Subsurface Oil and Gas Reservoirs

Reservoirs of oil and gas are geologically designed to hold the resource over long periods of time. This makes the reservoirs ideal storage locations for CO_2 sequestration. Depleted oil and gas reserves have a large volume of unoccupied space that can accommodate CO_2. Injecting CO_2 into an oil and gas reserve that is still being produced, although potentially becoming depleted, not only replaces reservoir volume, but also can enhance the secondary recovery of oil. The process of using a fluid or gas (e.g., water flood or CO_2 flood) to increase the amount of oil recovered from a reserve is referred to as EOR.

The CO_2 that is injected into a depleting oil reserve is dissolved into the remaining oil, lowering the viscosity of the oil and making it easier to extract. Using a supply of natural CO_2, this process has been incorporated into many reservoir production plans by the oil and gas industry since the 1970s. Currently, there are five large fields in the U.S. using natural sources of CO_2 for EOR. Additionally, many oil and gas companies have practiced disposing of acid gas (mainly CO_2 with some hydrogen sulfide, or H_2S) by first removing the gas from the product, compressing the gas, transporting it to an injection well, and re-injecting the acid gas into a different formation. It has been argued that this practice has less environmental impact than disposing or processing the acid gas at a facility.

The technology for injecting CO_2 for EOR is mature, especially in the Permian Basin of western Texas and eastern New Mexico. However, loss of the injected CO_2 to the formation for most EOR projects is minimized by design. As with CO_2-ECBM projects, using industry supplied anthropogenic CO_2 for EOR is a value-added benefit. Not only is the CO_2 sequestered, but the amount of oil that can be recovered from a reserve using CO_2 injection is approximately 10 to 15 percent of the original oil in the reserve.

3.3.5.2.1 Example Oil and Gas Reservoir Sequestration Project – Weyburn, Saskatchewan

The Williston Basin covers portions of Montana, North and South Dakota, Manitoba, and Saskatchewan. Hydrocarbon resources in the basin are plentiful and have been produced for many years. The Weyburn Oil Field, located in the northeast part of the Williston Basin, was discovered in 1954 and produced oil using standard methods (primary production) until 1964 when the water flood method was utilized to begin secondary recovery of oil. In 2000, Weyburn began the CO_2 flood, which will extend the life of the field by approximately 25 years making it the sixth largest recovery project in the world. The Weyburn Oil Field is currently operated by EnCana Resources and is part of an international research effort coordinated by the Canadian Petroleum Technology Research Centre and International Energy Agency Greenhouse Gas Research and Development (EnCana, 2005).

The CO_2 sequestration at the Weyburn Oil Field in Saskatchewan and Statoil's Sleipner Natural Gas Field in the North Sea are two of the largest projects actively sequestering CO_2 in geologic formations. A lignite-fired Dakota Gasification Company synfuels plant in North Dakota supplies the CO_2 to Weyburn. It is estimated that, over the approximately 25-year life of the CO_2-EOR project at Weyburn, about 16 million metric tons of CO_2 from the Dakota Gasification Facility will be injected and about 130 million barrels of oil will be produced. The study of the Weyburn project, therefore, allows scientists to determine the particular challenges associated with injecting fossil fuel supplied CO_2 rather than using a natural supply of CO_2, as is more common in EOR (Suebsiri et. al., 2004).

At the CO_2-EOR Weyburn project, it has been estimated that approximately half of the injected CO_2 remains in the oil that will not be harvested. The other half of the injected CO_2 is dissolved into the oil, making the oil easier to extract. Once back at the surface, the CO_2 is recovered, compressed, and reinjected into the formation for continued EOR and storage (IEA, 2004).

Geology in the Weyburn Project Area

The Weyburn Oil Field lies on the northeastern rim of Williston Basin, in southeastern Saskatchewan, Canada. The Williston Basin forms the southeastern extremity of the Western Canada Sedimentary Basin. These 70 square miles in Saskatchewan constitute one of the largest medium-sour crude oil reserves in Canada (Alberta Geological Survey, 1994; North Dakota, 2004).

The oil field lies at the updip end of the annular facies deposited during Mississippian time (Mississippian reservoirs account for most of the oil production in the basin). Bituminous basal carbonates store the hydrocarbon resources and are trapped by the stratigraphic layering and inter-fingering of mudstones and carbonates. Evaporites form both the top and bottom seals of the production zones. In the Weyburn field, two layers of the Midale Unit, part of the Madison Group, produce the oil. The Marly Zone is a chalk dolomite with a low permeability. The Vuggy Zone lies stratigraphically below the Marly Zone and is a highly fractured and permeable limestone. The water flood-recovery technique was quite successful in the Vuggy Zone, however, was unable to produce oil from the hydraulically tight Marly Zone. A significant amount of oil still resides in the Marly Zone, and it is hoped that the CO_2 flood is more successful for secondary recovery from this zone (Haidl et al., 2004).

The Weyburn reservoir is covered by a caprock, the Midale Evaporite, that is between 15 and 35 feet thick and is present at about 4,600 feet below ground surface (Nickel, 2004). The unit is a succession of anhydrites and dolostones. Fractures have been identified in the Midale Evaporite Unit; however, none of the fractures appear to transmit fluids. The Frobisher Evaporite is located stratigraphically below the Weyburn reservoir and ranges between 0 (in the southern portion of the field) and 23 feet thick. This evaporite consists of anhydrite with dolomudstone. Updip and north of the Weyburn reservoir is a 6 to 33 feet thick zone of alteration associated with an unconformity surface. This zone of alteration has substantially decreased porosity in the Midale Units creating a third, updip seal for the reservoir.

3.3.5.2.2 Groundwater in the Weyburn Project Area

Groundwater in the Williston Basin generally flows from the south-southwest to the north-northeast across the basin (Baker, 1999). There are two main groundwater flow regimes in the area of the Weyburn Oil Field: the Lower Paleozoic and Mississippian (e.g., Midale) Aquifer Groups, and the Mesozoic Aquifer Group. The Midale Aquifer (in the Mississippian Group) has an average intrinsic permeability of 35 millidarcy. The Jurassic and Mannville Aquifers in the Mesozoic Aquifer Group that overlie the Midale Aquifer have permeabilities that exceed 10 darcy. The Watrous Aquitard hydraulically separates the Midale Aquifer from the Jurassic Aquifer.

There appears to be very little vertical flow between aquifers as most of the flow is lateral within a given unit. The variations in water chemistry between the two groundwater flow regimes indicate that the Watrous Aquitard is competent; and the upper, less saline, higher permeability aquifers are effectively isolated from the CO_2 injection aquifer (Midale) by the Watrous Aquitard (Khan and Rostron, 2004).

3.3.5.2.3 Geologic Hazards in the Weyburn Project Area

The Williston Basin is a roughly circular-shaped area that has been subsiding very slowly over the past half-billion years. The basin contains various structural components (anticlines) creating the configuration of the basin, and its faults and fractures. Most geologic hazards present are a direct response of the natural system to anthropogenic intrusion, including mining and oil and gas production (Gibson, 1995).

3.3.5.2.4 Preliminary Results from the Weyburn Project

The Weyburn CO_2-EOR site is currently monitoring many aspects of the hydrogeologic and sequestration systems to further the understanding of the mechanisms of CO_2 storage in oil reservoirs. This project allows for the demonstration of carbon sequestration with EOR at full-scale, rather than a bench-, pilot-, or laboratory-scale. Various site selection parameters and models have been developed using the data collected at Weyburn, and several MM&V technologies are being field-tested.

Data collection began prior to the initial CO_2 flooding in 2000 to establish field characteristic prior to the injection of the CO_2. Data have also been collected during injection to compare the results. During the study, scientists conducted long-term risk assessments, completed geological and seismic studies, matched reservoir modeling against actual production results, and performed repeated and frequent sampling to understand the chemical reactions occurring within the reservoir due to CO_2 injection. Researchers with the Canadian Petroleum Technology Research Centre have succeeded in tracking the flow of the injected CO_2 underground. Mathematical models have been developed that show 100 percent of the injected gas will remain underground even after 5,000 years (Rigzone, 2004). Additionally, these models indicate that no injected CO_2 will enter the overlying drinking water sources and there will be no venting of the sequestered CO_2 to the atmosphere. Other observations and conclusions from the work completed at Weyburn are summarized below.

- The large number of oil wells in the field could present potential pathways for CO_2 escape. These wells should be monitored and, if gas is detected, mitigation efforts performed immediately.

- Seismic surveys are useful to visualize the CO_2 as it flows within the geologic units and mixes with the oil reserves.

- Mathematical models are practical tools to predict storage capacity of the reservoir and should be updated and calibrated through time as data becomes available from the injection project.

3.3.5.2.5 Application of Oil Reserve Sequestration in Other Locations

Physical characterization of the oil reserve that is to be used in any potential CO_2 sequestration project is generally complete. Most of the reservoir, geologic, and tectonic framework of the area will have been studied as part of the initial project development. However, the seals to the system (i.e., the caprock and lateral structures or geologic features that will prohibit the migration of the sequestered CO_2) will need to be studied (Figure 3-22). There are many natural analogs and current projects that can be evaluated to further the conceptualization of the geologic site conditions that could be affected by the sequestration technologies. Currently, there are at least 75 CO_2-EOR projects in the U.S. (mainly in Texas, but also in Oklahoma, Louisiana, Colorado, and Arkansas) that can be studied to gain further knowledge.

Basins with a moderate to high potential for oil reservoir sequestration projects are summarized in the following list. Refer to Figure 3-16 and Figure 3-17 for the oil and gas regions noted.

- Alaska (Northern, Central, and Southern)
- Anadarko
- Central Coastal
- Green River
- Michigan.
- Permian
- Powder River
- San Joaquin
- San Juan
- Santa Maria
- Southern Oklahoma
- Ventura
- Williston
- Wind River

Although the geologic resources in the potential locations of oil reservoir sequestration sites listed above can vary greatly, several generalizations can be made that provide some initial site selection characteristics. These characteristics were determined to be essential to minimize the effect of the sequestration activities on the geologic resources of an area. A summary of geologic conditions anticipated for successful oil reservoir sequestration is outlined on the next page.

- The oil reservoir would be deep, generally more than several thousand feet below ground surface.

- The target reservoir would be hydrogeologically isolated from any potable water aquifer (e.g., thick and laterally continuous, low-permeability unit between the reservoir and any potable water supply).

- Permeable faults and fractures should not extend through the sequestration reservoir caprock in the project area, and any structures occurring in the area would preclude water moving upward from the reservoir into shallow aquifers.

- No significant geologic hazards should exist in the project area, and active faults would be avoided.
- The oil reservoir would be laterally confined (generally by geologic structure) to prevent potential migration of injected CO_2.
- In most oil fields, there are many active and abandoned wells that extend to the target formation depth. These wells would need to be properly monitored or decommissioned in order to cut off any vertical migration pathway.
- Over-pressuring the formation due to CO_2 injection could induce seismic activity. This activity could exhibit surficial characteristics or only affect the target formation. In either case, the CO_2 could become mobile through the induced fractures; therefore, seismic activity in the vicinity of the sequestration site should be closely monitored and evaluated.
- The sequestration site would be located near the CO_2 source to minimize the effects of the CO_2 transportation on the area.

3.3.5.3 Sequestration in Saline Water-Bearing Formations

The use of saline water-bearing formations to sequester CO_2 differs from sequestration in unmineable coal seams and oil reservoirs in the following ways. First, unlike CO_2-ECBM or CO_2-EOR projects, injection of CO_2 into a saline water-bearing formation may not provide an economic benefit. In other words, many formations containing saline water may be used for CO_2 sequestration without producing a resource (e.g., petroleum) that could be sold to offset the cost of the sequestration. On the other hand, saline water-bearing formations are more ubiquitous in the U.S. than either coal seams or oil reserves. This would allow shorter transport distances for the injected CO_2 from source locations, and create a much larger potential sink for the sequestration of CO_2. Research has indicated that sequestration of CO_2 in saline water-bearing formations is the most promising long-term option available to date.

Saline water-bearing formations are layers of porous rock that are saturated with brine water. The high total dissolved solids (TDS) content of the water precludes its use for either domestic or agricultural purposes. These formations are generally found at great depths, which is an essential component for the successful sequestration of CO_2 in saline systems. Based on the current understanding of the systems, it has been determined that the CO_2 should be injected at depths greater than 2,625 feet (800 meters) not only to ensure a long flow path to the surface if the gas escapes the formation, but also to keep the CO_2 in the dense phase. At this depth, the pressure and temperature present are such that the gas will not exist in either a gas or liquid phase, but rather an immiscible supercritical phase with high density. The specific gravity of the CO_2 is lower than that of the brine so the CO_2 rises to the top of the reservoir. The CO_2 can be further trapped by the solubility and mineral trapping mechanisms (e.g., dissolution of CO_2 into fluids and the reaction of CO_2 with minerals present in the host formation to make stable compounds such as carbonates) present in the saline water-bearing formation. This ensures efficient storage of the CO_2 and implies that the CO_2 may be fixed or dissolved before reaching a basin margin.

Characterization of the saline water-bearing formation may require more initial work than for other geologic sequestration sites as less work has been completed on the sequestration target historically. Often, however, saline water-bearing formations occur in the same area as oil and gas reserves, where data are plentiful.

Table 3-25 depicts some of the most prominent deep saline formations in the U.S. These formations include:

- Arbuckle Group (Oklahoma)
- Cape Fear (South Carolina Coastal Plain)
- Carbonate Basin Fill (Basin and Range)
- Cedar Keys/Larson (Florida)
- Fox Hills (Powder River Basin)
- Frio (Gulf Coast Basin)
- Glen Canyon (Kaiparowitz Basin)
- Granite Wash (Palo Duro Basin)
- Jasper (Gulf Coast Basin)
- Lower Potomac (North Atlantic Coast)
- Lyons Sandstone (Denver Basin)
- Madison Formation (Williston Basin)
- Morrison (San Juan Basin)
- Mt. Simon (Ohio-Michigan area)
- Oriskany Sandstone (Appalachian Basin)
- Paluxy Formation (East Texas Basin)
- Pottsville (Black Warrior Basin)
- St. Peter (Illinois Basin)
- Tuscaloosa (Coastal Alabama)

Summaries of most of these formations as they relate to potential carbon sequestration activities are available in the Phase I Topical Report "Technical Summary: Optimal Geological Environments for Carbon Dioxide Disposal in Brine Formations (Saline Formations) in the U.S." by the Bureau of Economic Geology, University of Texas as Austin, sponsored by NETL (available at http://www.beg.utexas.edu/environqlty/co2seq/finalreport.pdf).

Several generalizations can be made that provide some initial site selection characteristics. A summary of geologic conditions anticipated for successful sequestration in saline water-bearing formations is outlined below.

- The target saline water-bearing formation would be deep underground (at least 2,625 ft, or 800 m below ground surface) to allow injected CO_2 to stay in the dense phase.
- The target formation would be hydrogeologically isolated from any potable aquifer (e.g., thick and laterally continuous, low-permeability unit between the reservoir and any potable water supply).
- Faults and fractures would be minimal in the project area, and any structures occurring in the area would not transmit water vertically between geologic units. No significant geologic hazards should exist in the project area.
- The saline water-bearing formation would be laterally confined (generally by geologic structure) to prevent potential migration of injected CO_2. Alternatively, the formation will be of great enough lateral and areal extent that the injected CO_2 would have time to undergo solubility or mineral trapping in the groundwater flow regime.

- Many saline water-bearing formations occur in conjunction with oil and gas resources. In most oil fields, there are many active and abandoned wells that extend to the target formation depth and beyond. These wells would need to be properly monitored or decommissioned in order to cut off any vertical migration pathway.

- The sequestration site would be located near the CO_2 source to minimize the effects of the CO_2 transportation on the area.

Saline formations under current study by the Regional Partnerships are shown in Figure 3-24.

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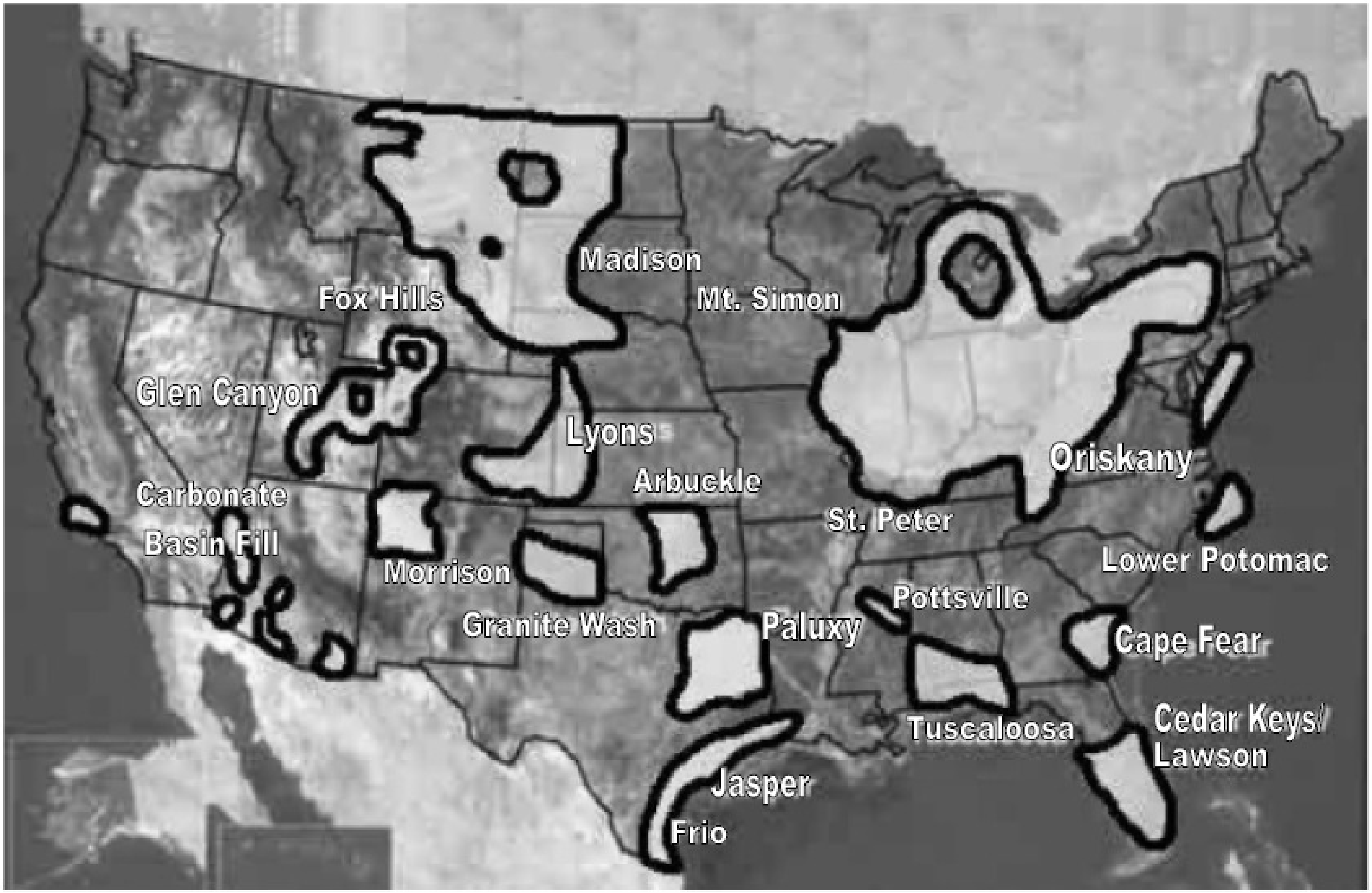

Source: DOE, 2002.

Figure 3-23. Deep Saline Formations in the U.S

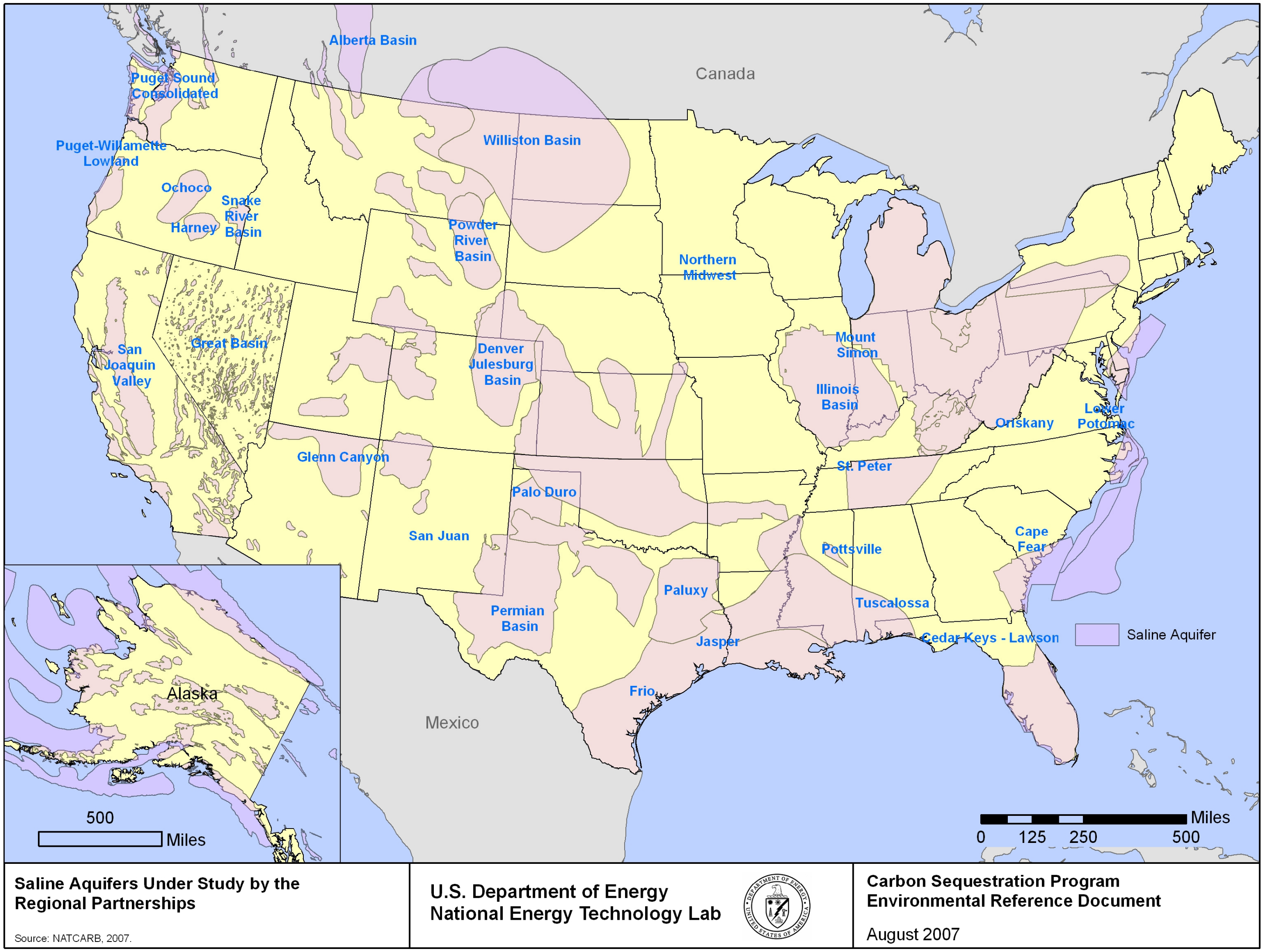

Figure 3-24. Saline Formations under Evaluation by the Regional Partnerships

3.3.5.3.1 Example of a Saline Water-Bearing Formation Sequestration Project – Frio Formation, Liberty County, Texas

The University of Texas at Austin's Bureau of Economic Geology is currently conducting a small-scale field test of the saline water-bearing formation sequestration technologies. The test site is located in the South Liberty Oil Field about 40 miles inland of the Gulf of Mexico, just northeast of Houston. The oil field was discovered in 1925 and produced in various stages through most of the 1900s. There are currently about 650 wells in the oil field, some producing and some abandoned.

The target formation, the Frio Formation, is about 5,000 feet below ground surface and is stratigraphically above the depleted oil reserve in the area. A new injection well was recently completed to 5,753 ft below ground surface and an older well was modified to become an observation well approximately 100 feet updip from the injection point (Techline, 2004). The injected CO_2 was supplied from a BP oil refinery in Texas City, Texas, and in October 2004, approximately 1,600 tons of CO_2 was injected during the 9-day test (Hovorka et al., 2005).

3.3.5.3.2 Geology in the Frio Brine Pilot Project Area

The Frio Project Site is located in an area of low topographic relief in the lower coastal plain of the Gulf of Mexico on the terrace above the Trinity River (NETL, 2003). The area gently dips towards the Gulf and is transected every few miles by northeast-trending (southeast down drop) growth faults. Additionally, there are numerous salt domes in the area that disrupt the geology and structures.

The injection zone is the Frio Sandstone, which contains a brine groundwater formation, located on the southwest flank of the South Liberty Salt Dome. The Frio is laterally limited within a fault-bounded compartment. There is approximately 200 feet of shale (Anahuac Shale Unit) above the Frio, creating the caprock for the system, and about 4,200 feet of inter-bedded sandstones and shales above the Anahuac Formation. The total thickness of the Frio is about 2,000 feet; however, the injection zone is near the top of the unit (the injection well is screened from 5,053 to 5,073 feet below ground surface) (Techline, 2004). Hydrocarbons were produced from the interval between 8,000 and 9,000 feet below ground surface, and a thick shale unit lies stratigraphically between the depleted hydrocarbon zone and the brine system.

The 70-feet thick test interval has an average porosity of 27 percent and a measured intrinsic permeability between 50 and 242 millidarcy, as reported in June 2004. More recent testing reported April 2005 indicates an inter-well permeability of approximately 2.3 darcy. In this area, the Frio dips approximately 16 degrees to the south. The pressure and temperature recorded in the injection interval are about 2,211 psi and 135°F. The salinity in the Frio at this location ranges from 100,000 to 125,000 ppm, equivalent to milligrams per liter.

3.3.5.3.3 Soils in the Frio Brine Pilot Project Area

There are generally three soil units in the area of the Frio Project Site. In the uplands, the dominant soils are thick with textures ranging from very fine sandy loam to clay, and potentially sandy clay loam to clay. The Woodville fine sandy loams are found on the bluff between the upland and the Trinity River flood plain. Very deep, wet, and poorly drained clay to silty clay soils of the Kaman unit are located on the Trinity River flood plain. Additionally, alluvium deposits are found in the area, especially on the flood plain. The dominant soil texture at the site is sandy loam.

3.3.5.3.4 Groundwater in the Frio Brine Pilot Project Area

Groundwater and surface water systems are generally interconnected, and the location of the main channel of the Trinity River only about 1.5 miles east of the Frio Project Site would suggests that there are areas of groundwater near the surface (potentially perched). Fresh groundwater in the area is found near the surface in the alluvium and Beaumont units and in the Upper and Lower Chicot and Evangeline Formations. The base of the useable groundwater (groundwater with concentrations of TDS less than

3,000 ppm) in the area is at about 2,200 feet below ground surface. Below the Evangeline Aquifer is the Burkeville confining unit, which seems to effectively separate the useable groundwater from marginal quality groundwater (concentrations of TDS less than 10,000 ppm) below. This zone of marginal quality groundwater extends to about 3,400 ft below ground surface, approximately 1,600 feet above the CO_2 injection zone in the Frio. Additionally, 200 feet of the Anahuac Shale Formation lie stratigraphically between the useable groundwater and the injection zone (Techline, 2004).

3.3.5.3.5 Geologic Hazards in the Frio Brine Pilot Project Area

As described above, there are some faults and fractures in the area of the Frio test site. Based on evaluations conducted in conjunction with the oil and gas production in the area, these faults act as barriers to compartmentalize the hydrostratigraphy of the area, rather than as conduits for fluid or gas migration. It has yet to be determined how these faults and fractures will behave with the increased pressure from the injected CO_2. Additionally, with the site located on the Trinity River flood plain, there is the potential for flooding in the project area.

3.3.5.3.6 Preliminary Results from the Frio Brine Pilot Project

Prior to the initiation of the CO_2 injection in October 2004, various geologic and hydrogeologic characteristics were measured and monitored to create a baseline for the later comparison of data collected during and following the injection. These baseline data collection methods included the following;

- Collecting groundwater samples and using the laboratory analyses results to generate a site-specific model of the aqueous geochemistry.
- Conducting wire-line logging, cross-well seismic, cross-well electromagnetic imaging, and vertical seismic profiling to determine the configuration of the subsurface between the injection and observation wells.
- Hydrologic testing in two wells to assess various groundwater movement characteristics.
- Surface water and gas monitoring to establish baseline levels.

During the 9-day injection test and following the injection, monitoring was repeated and extensive methods were used to monitor the movement of the injected CO_2 (Techline, 2004). Three (3) tracers were utilized to follow the travel path of the injected CO_2.

Preliminary results indicate that the pressure domain in the test site was more complex than hypothesized due to the producing wells in the South Liberty Oil Field. Additionally, the modeling and results analyses were complicated by the heterogeneity present in the sandstones.

3.3.5.3.7 Application of Saline Water-Bearing Formation Sequestration in Other Locations

Studying the characteristics and results of the CO_2 injection test at the Frio Project Site will yield valuable information for much of the Gulf Coast region. Similar salt water-bearing formations exist in the region from coastal Alabama to Mexico, and many of these formations are located near refineries and industrial processing plants that produce large amounts of CO_2 that could be used in sequestration projects. The high-permeability, large-volume sandstones characteristic to this region are ideal for sequestration projects, assuming competent seals are present. Using the short-term, pilot-test results obtained at Frio, scientists will be able to better define variables that control CO_2 injection and migration. The data can be used in project conceptualization and model calibration in the planning, development, and monitoring phases of additional sequestration projects.

In addition to the Frio project, there are many other projects that can be studied to further the knowledge of saline water-bearing formation sequestration of CO_2 such as the Midwestern U.S. Project operated by Battelle, and the Statoil Project at the Sleipner West Natural Gas Production Facility (injecting deep in the Utsira Formation, a saline water-bearing formation beneath the North Sea at approximately 3,280 ft deep).

3.3.5.4 Basalt Formation Sequestration

Basalt formations exist throughout the U.S., and elsewhere in many areas around the world. In some locales, these formations may be attractive targets for CO_2 sequestration, if they have relatively high permeability, because they appear to have favorable geochemical properties for converting the injected CO_2 to solid mineral forms, and thus over long periods may permanently isolate the CO_2 from the atmosphere (NETL, 2004). Basalt is a type of volcanic rock that is formed when magma high in aluminum, silica, calcium, iron and magnesium extrudes to the ground surface, flows out as lava, and is solidified. Commonly, basalt rock formations have porous characteristics (including cooling joints and pore spaces caused by rapid cooling and escape of gases at the surface) that create permeability in an otherwise solid rock mass. Coarse rubble zones, caused by varied cooling and flowing rates, are found above and below more dense rock. Often sand and gravel is deposited on top of or within the rubble zones, which create the relatively high bulk permeability. However, the centers of the lava flows are dense, typically unfractured and thus much less permeable. Stream flow deposits and zones of blocky rubble usually follow the flow trend so the highest permeability of the formations is parallel to the lava flow direction. The permeability of the basalt can decrease with geologic time as alteration by deep burial or the influx of cementing fluids fills available pore spaces and fractures (Freeze and Cherry, 1979).

Flood basalt formations are, by definition, multiple lava flows of huge volume (on the order of 5-10 cubic km or more) while plain basalt formations have individual flow volumes generally much less than 1 cubic km (USGS, 2005). There is evidence that aquifers in various flood and plain basalt flows are isolated, however the integrity of those natural seals with respect to the injection of CO_2 would need to be investigated at a field-scale test (Manancourt and Gale, 2004).

The theory behind sequestering CO_2 in basalt formations includes the chemical, or mineralogical, trapping of the injected CO_2. Under certain reservoir conditions, the CO_2 reacts with the minerals in the formation releasing cations (mainly calcium, magnesium, and iron) into solution and precipitating as carbonate minerals (e.g., calcium carbonate, $CaCO_3$) (Schaef, et al., 2004).

Major basalt formations in the U.S are shown in Figure 3-25 and include:

- Keweenawan Formation: The Keweenawan formation was formed during the rift event that created the Lake Superior Craon (UWM, 2005). The system is approximately 35,000 feet thick, however, the total thickness of the basalt units is unknown due to the formation abutting to the Keweenawan Fault (Butler and Burbank, 1929). About 24,000 cubic miles of lava extruded (CRR, 2005). The typical Keweenawan basalt flow grades from olivine composition through andesitic to rhyolitic basalt (Butler and Burbank, 1929).
- East Continental Rift Zone: The East Continental Rift Zone is a basin filled with sedimentary and volcanic rocks (UK, 2005). The mafic volcanic rocks are fractured, however, the extent of the fracturing is unknown (Drahovzal and Harris, 2004). The Newark Supergroup was accumulated in a half-graben associated with extensional faulting (Geowords, 2005; Schlische, 1992). There are three quartz-normative tholeiitic basalt flows interbedded with lake-level sediment cycles Hook Mountain, approximately 360 feet thick; Preakness, approximately 820 feet thick; and Orange Mountain, approximately 490 feet thick (Schlische, 1996 and 1992).

Figure 3-25. Primary Basalt Formations

Source: Battelle, 2005.

- Southeast Rift Zone: This zone is a fault-bounded extensional basin that is part of the North American rifted margin. This rift zone formed during the breakup of the Pangean supercontinent and the formation of the Atlantic Ocean. These basalt formations, also known as the South Georgia Rift Formations or the Clubhouse Crossroads Basalts, are part of the Central Atlantic Magmatic Province and are classified as tholeiitic basalts. The basalt composition has high sodium and potassium with low silica group inclusions only in the stratigraphically lower Clubhouse Crossroads basalt (Branton et al, 2001). The basalt flows are areally extensive with an implied area greater than 38,000 square miles (McBride et al, 1989).

- Southern Nevada Volcanics: The Southern Nevada Volcanics basalt formations are thickest in the central part of the flows (about 650 feet thick) with the individual flows generally less than 30 feet thick. The composition of these basalts ranges from calc-alkaline andesite, to dacite, to olivine (USGS, 2005).

- Northern California Volcanics: The Northern California Volcanics are a massive platform of basalts that overlies the western Cascades (Siskiyous, 2005). Known as the High Cascades, the formations are a result of subduction-related volcanism and consist mainly of basalt and basaltic andesite, which are magnesium rich (Siskiyous, 2005 and USGS, 2005). Basalt flows are also present in the vicinity of Mt. Lassen, a volcano in northern California, which is located at the southern end of the Cascade Arc (UW, 2005).

- Snake River Plain: The Snake River Plain basalt formation is found in southern Idaho and western Oregon. The normal fault-bounded basin is filled with plain basalt formations interbedded with lakebed sediments covering an area of 8,000 square miles with basalts flows on an average of 5,000 ft thick (ISU, 2005 and USGS, 2005). These basalt flows consist of sequences of thin, individually cooled units less than 3 ft to greater than 30 ft thick (ISU, 2005). The composition of formation varies, but is mainly silicic and basaltic volcanic, with rhyolite more abundant than basalt. In this area, the rhyolite and basalt flows often alternate with deposits of extensive volcanic tuff and ash flows (ISU, 2005). Many of the faults and large fracture zones extend into the plain from the basin margins (ISU, 2005).

- Columbia River Basalt Group (CRBG). The Columbia River Basalt Group (CRBG) is located in northern Oregon and southern Washington. This formation is one of the largest and most studied basalt formations in the world (WDGER, 2005). The four formations that comprise the CRBG cover over 63,000 square miles and have a volume of almost 42,000 cubic miles (WDGER, 2005). The thickness of these formations exceeds 6,000 ft in some locations (USGS, 2005). More than 300 individual, high-volume lava flows have been identified with an average volume of about 140 cubic miles (USGS, 2005 and UND, 2005). Most of the flows in the CRBG are tholeiitic basalts, which are typically quite dense. Limited zones of vesicular basalt are also interbedded with more extensive river-deposited sediments between flows (UND, 2005 and Freeze and Cherry, 1979). The relatively dense, unfractured portions of the basalt exhibit a low permeability and generally impede groundwater flow, thus acting as an aquitard (Freeze and Cherry, 1979). There is a small injection test planned (approximately 3,000 tons of CO_2) at a depth of about 3,000 ft in the Grande Roude member of the CRBG in eastern Washington (BSRCSP, 2005). Preliminary calculations indicate that the CRBG formations have favorable geochemical properties for converting injected CO_2 into carbonate minerals (PNL, 2005).

Although the geologic characteristics in the potential locations of basalt formation sequestration project sites vary greatly, several generalizations can be made that provide some initial site selection characteristics. A summary of geologic conditions anticipated for successful sequestration in basalt formations is outlined below. Since the use of basalt formations to sequester CO_2 has not been extensively studied, much of those data required for a successful project design are not available. Those necessary data include injectivity, storage capacity, and rate of conversion (NETL, 2004).

- The target basalt formation would be deep underground to allow the injected CO_2 to stay in the dense phase.

- The target formation would be hydrogeologically isolated from any potable aquifer (e.g., by a thick and laterally continuous, low-permeability unit between the basalt reservoir and shallower aquifers).

- Extensive or pervasive faults and fractures would be minimal in the project area, and any structures occurring in the area would not transmit water vertically between geologic units. Sites would be selected to avoid significant geologic hazards. If unavoidable, geologic hazards would be recognized during site characterization and the potential impacts would be mitigated by effective project design.

- The sequestration site would be located near the CO_2 source to minimize the effects of the CO_2 transportation to the area.

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3.4 SURFACE WATER RESOURCES

This section describes the surface water resources that may be affected by carbon sequestration projects. In this section, the term surface water is defined as rivers, streams, lakes, ponds, reservoirs, wetlands, estuaries and coastal waters. Groundwater is addressed in the section on geologic resources.

Protective water quality standards are important for the conservation and enhancement of fish, wildlife, and their habitats and for the continuing benefit of the American people. The objective of the Clean Water Act is to restore and maintain the chemical, physical, and biological integrity of the nation's waters. The goal of this law is to establish national water quality standards that provide for the protection of fish, shellfish, and wildlife as well as providing safe recreational use of the nation's water bodies.

Poor water quality can harm species and habitats, and must be assessed in activities such as wastewater discharge. Many factors are known to cause poor water quality including temperature, sedimentation, runoff, erosion, dissolved oxygen, pH, decayed organic materials, pesticides, and an array of other toxic and hazardous substances (USFW, 2004).

The EPA's 2000 Report to Congress on the status of U.S. water quality reported the following two leading causes of surface water pollution nationwide (EPA, 2000):

- Pollution from urban and agricultural land that is transported by precipitation and runoff (called nonpoint source pollution) is the leading source of impairment.
- Siltation, nutrients, bacteria, metals (primarily mercury) and oxygen-depleting substances are among the top causes of impairment.

Some of the problems caused by toxic and pathogen contamination include fish, wildlife and shellfish consumption advisories, drinking water closures, and recreational restrictions. EPA's National Listing of Fish and Wildlife Advisories database listed 2,838 advisories in effect in 2000. Ten (10) of 28 coastal states reported prohibited, restricted or conditionally approved shellfish harvesting in 1,630 square miles of estuarine waters. Thirteen states and tribes identified 233 sites where contact recreation was restricted at least once during the reporting cycle (EPA, 2000).

States, participating tribes and other jurisdictions measure attainment of the Clean Water Act goals by comparing monitoring data to the narrative and numeric criteria they have adopted to ensure support of each use designated for each specific water body. These uses include: aquatic life support, drinking water supply, fish consumption, shellfish harvesting, primary recreation (swimming), secondary recreation, agriculture, ground water recharge, wildlife habitat and cultural. Assessments are normally based upon five broad types of monitoring data: biological integrity, chemical, physical, habitat and toxicity data (EPA, 2000). In EPA's 2000 Report to Congress, an estimated 39 percent of U.S. rivers and streams were found impaired for one of more uses. Similarly, 45 percent of the more than 41 million acres of lakes and streams nationwide and 51 percent of estuaries were reported to be impaired for one or more uses (see Table 3-5). Table 3-6 provides information on surface water resources in each state.

Table 3-5. Surface Water Resources in the U.S.

Surface Water Resources	Entire United States	Percent Impaired for One or More Uses
Total Miles of Rivers and Streams	3,655,192	39%
Total Lake, Reservoir and Pond Acres	41,410,351	45%
Estuaries, Total Square Miles	71,709	51%
Ocean Shorelines, Total Miles	65,754	Not Evaluated

Source: EPA, 1998 and EPA, 2000.

Table 3-6. Surface Water Resources in Each State

State	Rivers and streams (miles)	Lakes, Reservoirs, and Ponds (acres)	Estuaries (square miles)	Ocean shoreline (miles)
Alabama	77,274	490,472	610	337
Alaska	365,000	12,787,200	33,204	36,000
Arizona	127,505	400,720	0	0
Arkansas	87,617	514,245	0	0
California	211,513	1,672,684	2,139	1,609
Colorado	107,403	164,029	0	0
Connecticut	5,830	64,973	612	380
Delaware	2,506	2,954	449	25
District of Columbia	39	238	6	0
Florida	51,858	2,085,120	4,437	8,460
Georgia	70,150	425,382	854	100
Idaho	115,595	700,000	0	0
Illinois	87,110	309,340	0	0
Indiana	35,673	142,871	0	0
Iowa	71,665	161,366	0	0
Kansas	134,338	188,506	0	0
Kentucky	49,105	228,385	0	0
Louisiana	66,294	1,078,031	7,656	397
Maine	31,752	987,283	2,852	5,296
Maryland	8,789	77,965	2,522	32
Massachusetts	8,229	151,173	223	1,519
Michigan	51,438	889,600	0	0
Minnesota	91,944	3,290,101	0	0
Mississippi	84,003	500,000	760	245
Missouri	51,978	293,305	0	0
Montana	176,750	844,802	0	0
Nebraska	82,258	280,000	0	0
Nevada	143,578	533,239	0	0
New Hampshire	10,881	168,017	21	18
New Jersey	8,050	72,235	725	127
New Mexico	110,741	997,467	0	0
New York	52,337	790,782	1,530	120
North Carolina	37,662	311,071	3,121	320
North Dakota	54,427	714,910	0	0
Ohio	29,113	188,461	0	0
Oklahoma	78,778	1,041,884	0	0
Oregon	115,472	618,934	206	362

State	Rivers and streams (miles)	Lakes, Reservoirs, and Ponds (acres)	Estuaries (square miles)	Ocean shoreline (miles)
Pennsylvania	83,161	161,445	0	0
Rhode Island	1,383	21,796	151	79
South Carolina	29,794	407,505	401	190
South Dakota	9,937	750,000	0	0
Tennessee	61,075	538,060	0	0
Texas	191,228	1,994,600	2,394	624
Utah	85,916	481,638	0	0
Vermont	7,099	228,920	0	0
Virginia	49,460	149,982	2,494	120
Washington	70,439	466,296	2,904	163
West Virginia	32,278	22,373	0	0
Wisconsin	55,000	944,000	0	0
Wyoming	108,767	325,048	0	0

Source: EPA, 2000.

3.4.1 Wetlands

In the 1600s, more than 220 million acres of wetlands are thought to have existed in the lower 48 states. Since then, extensive losses have occurred, and over half of the original wetlands have been drained and converted to other uses. The years from the mid-1950s to the mid- 1970s were a time of major wetland loss, but since then the rate of loss has decreased.

Between 1986 and 1997, an estimated 58,500 acres of wetlands were lost each year in the conterminous U.S. Various factors have contributed to the decline in the loss rate including implementation and enforcement of wetland protection measures and elimination of some incentives for wetland drainage. Public education and outreach about the value and functions of wetlands, private land initiatives, coastal monitoring and protection programs, as well as wetland restoration and creation actions have also helped reduce overall wetland losses (EPA, 2003).

The lower 48 states contained an estimated 105.5 million acres of wetlands in 1997. This is an area about the size of California. In the 1980s, an estimated 170 to 200 million acres of wetland existed in Alaska (covering slightly more than half of the state), while Hawaii had 52,000 acres. Next to Alaska, Florida (11 million), Louisiana (8.8 million), Minnesota (8.7 million), and Texas (7.6 million) have the largest wetland acreage. Total wetland area and historic losses for each state are listed in Table 3-8 in Section 3.5 Biological Resources.

3.4.2 Rivers

A list of major rivers within the U.S. is provided in Table 3-7.

Table 3-7. Major Rivers of the United States

River	Length	Flows Into	States Traversed or Bordering
Alabama-Coosa	600 mi (966 km)	Mobile River	GA, AL
Altamaha-Ocmulgee	392 mi (631 km)	Atlantic Ocean	GA
Apalachicola – Chattahoochee	524 mi (843 km)	Gulf of Mexico	NC, SC, GA, AL, FL
Arkansas	1,459 mi (2,348 km)	Mississippi River	CO, KS, OK, AR
Brazos	923 mi (1,485 km)	Gulf of Mexico	NM, TX
Canadian River	906 mi (1,458 km)	Arkansas River	CO, NM, TX, OK

River	Length	Flows Into	States Traversed or Bordering
Cimarron	600 mi. (966 km)	Arkansas River	NM, OK
Colorado	862 mi. (1,387 km)	Matagorda Bay	CO, UT, AZ, NV, CA
Columbia	1,243 mi (2,000 km)	Pacific Ocean	WA, OR
Colville	350 mi (563 km)	Beaufort Sea	AK
Connecticut	407 mi (655 km)	Long Island Sound	VT, NH, MA, CT
Cumberland	720 mi (1,159 km)	Ohio River	KY, TN
Delaware	390 mi (628 km)	Delaware Bay	NJ, PA, NY
Gila	649 mi. (1,044 km)	Colorado River	NM, AZ, CA
Green	730 mi (1,175 km)	Colorado River	ID, WY, UT
Illinois	420 mi (676 km)	Mississippi River	IL
James	710 mi (1,143 km)	Missouri River	ND, SD, NE
Kanawha-New	352 mi (566 km)	Ohio River	NC, VA, WV
Kansas	743 mi (1,196 km)	Missouri River	CO, KS
Koyukuk	470 mi (756 km)	Yukon River	AK
Kuskokwim	724 mi (1,165 km)	Kuskokwim Bay	AK
Licking	350 mi (563 km)	Ohio River	KY, OH
Little Missouri	560 mi (901 km)	Missouri River	WY, MT, SD, ND
Milk	625 mi (1,006 km)	Missouri River	MT
Mississippi	2,348 mi (3,779 km)	Gulf of Mexico	MN, WI, IA, MO, IL, KY, AR, TN, LA, MS
Mississippi-Missouri-Red Rock	3,710 mi (5,970 km)	Gulf of Mexico	MT, ND, SD, NE, IA, MO, KS, IL, TN, AR, MS, LA
Missouri	2,315 mi (3,726 km)	Mississippi River	MT, ND, SD, NE, KS, MO
Missouri – Red Rock	2,540 mi (4,090 km)	Mississippi River	ID, MT, ND, SD, NE, IA, KS, MO
Mobile-Alabama-Coosa	645 mi (1,040 km)	Mobile Bay	GA, AL
Neosho	460 mi (740 km)	Arkansas River	KS, OK
Niobrara	431 mi (694 km)	Missouri River	WY, NE
Noatak	350 mi (563 km)	Kotzebue Sound	AK
North Canadian	800 mi (1,290 km)	Canadian River	NM, TX, OK
North Platte	618 mi (995 km)	Platte River	CO, WY, NE
Ohio	981 mi (1,579 km)	Mississippi River	PA, OH, WV, IN, KY, IL
Ohio-Allegheny	1,306 mi (2,102 km)	Mississippi River	PA, OH, IN, IL
Osage	500 mi (805 km)	Missouri River	KS, MO
Ouachita	605 mi (974 km)	Red River	AR, LA
Pearl	411 mi (661 km)	Gulf of Mexico	MS, LA
Pecos River	926 mi (1,490 km)	Gulf of Mexico	NM, TX
Pee Dee-Yadkin	435 mi (700 km)	Winyah Bay	NC, SC
Pend Oreille-Clark Fork	531 mi (855 km)	Columbia River	MT, ID, WA
Platte	990 mi (1,593 km)	Missouri River	CO, WY, NE
Porcupine	569 mi (916 km)	Yukon River	AK
Potomac	383 mi (616 km)	Chesapeake Bay	MD, VA, WV
Powder	375 mi (603 km)	Yellowstone River	MT, WY
Red	1,290 mi (2,080 km.)	Mississippi River	NM, TX, AR, LA
Red (also called Red River of the North)	545 mi (877 km)	Lake Winnipeg	MN
Republican	445 mi (716 km)	Kansas River	CO, NE, KS
Rio Grande	1,900 mi (3,060 km.)	Gulf of Mexico	CO, MN, TX
Roanoke	380 mi (612 km)	Albemarle Sound	VA, NC

River	Length	Flows Into	States Traversed or Bordering
Sabine	380 mi (612 km)	Sabine Lake	TX, LA
Sacramento	377 mi (607 km.)	Suisun Bay	CA
Saint Francis	425 mi (684 km)	Mississippi River	MO, AR
Salmon	420 mi (676 km)	Snake River	ID
San Joaquin	350 mi (563 km)	Suisun Bay	CA
San Juan	360 mi (579 km)	Colorado River	CO, NM, UT
Santee-Wateree-Catawba	538 mi (866 km)	Atlantic Ocean	NC, SC
Smoky Hill	540 mi (869 km)	Kansas River	CO, KS
Snake River	1,038 mi (1,670 km)	Columbia River	ID, OR, WA
South Platte	424 mi (682 km)	Platte River	CO, NE
Stikine	379 mi (610 km)	Stikine Strait	AK
Susquehanna	444 mi (715 km)	Chesapeake Bay	PA, MD, DE
Tanana	659 mi (1,060 km)	Yukon River	AK
Tennessee	652 mi (1,049 km)	Ohio River	TN, GA, AL, MS, KY
Tennessee-French Broad	886 mi (1,417 km)	Ohio River	KY, TN, AL, NC
Tombigbee	525 mi (845 km)	Mobile River	MS, AL
Trinity	360 mi (579 km)	Galveston Bay	TX
Wabash	512 mi (824 km)	Ohio River	OH, IL, IN
Washita	500 mi (805 km)	Red River	TX, OK
White	722 mi (1,160 km)	Mississippi River	AR
Wisconsin	430 mi (692 km)	Mississippi River	WI
Yellowstone	692 mi (1110 km)	Missouri River	ID, WY, MT
Yukon River	1,979 mi (3,185 km)	Bering Sea	AK

Source: Infoplease, 2004.

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3.5 BIOLOGICAL RESOURCES

This section describes the ecological resources that may be affected by carbon sequestration research projects and future commercial deployment. This discussion is based on ecoregions of the U.S. as presented in the National Atlas (DOI, 2000).

Ecoregions, or ecosystems of regional extent, are areas that share common climatic and vegetation characteristics. The U.S. Forest Service developed the following four-level hierarchy to differentiate ecoregions (USFS, 2004):

- Domains - Areas of related climates – differentiated based on precipitation and temperature.
- Divisions - Representative climates within domains – differentiated based on precipitation levels and patterns as well as temperature.
- Provinces - Areas within a division differentiated based on vegetation or other natural land covers. Mountainous areas that exhibit different ecological zones based on elevation are identified at the province level.
- Sections - Subdivisions of provinces based on terrain features.

Four ecological domains (humid temperate, dry, humid tropical and polar) are used for worldwide ecoregion classification and all four appear in the continental U.S. (Figure 3-26). The following discussion of biological resources of the U.S. is based primarily on these domains (Bailey, 1995).

3.5.1 Vegetation

The following paragraphs summarize the vegetation in each of the ecological domains across the continental U.S., including Alaska.

3.5.1.1 Humid Temperate Domain

The humid temperate domain is located in the middle latitudes (30 to 60 degrees North), where the climate is governed by both tropical and polar air masses. The domain is characterized by pronounced seasons, with strong annual cycles of temperature and precipitation including a distinctive winter season.

In the coastal ranges of the Pacific Northwest, Douglas fir, red cedar, and spruce grow to great heights. A combination of wet winters with dry summers, as found in central California, produces a distinctive natural vegetation of hard leaved evergreen trees and shrubs called sclerophyll forest. Trees and shrubs must withstand the severe summer drought (2 to 4 rainless months) and severe evaporation.

This domain encompasses the eastern half of the U.S. Much of the sandy coastal region of the Southeastern U.S. is covered by second-growth forests of longleaf, loblolly, and slash pines. Inland areas have deciduous forest. Needleleaf and mixed needleleaf-deciduous forests grow throughout the colder northern parts of the humid temperate domain, extending into the mountain regions of the Adirondacks and northern New England.

In the Midwestern portion of the U.S., vegetation is known as winter deciduous forests, dominated by tall broadleaf trees that provide a continuous dense canopy in summer, but shed their leaves completely in winter. Lower layers of small trees and shrubs are weakly developed. In spring, a luxuriant ground cover of herbs quickly develops, but is greatly reduced after trees reach full foliage and shade the ground.

3.5.1.2 Dry Domain

The essential feature of a dry climate is that annual losses of water through evaporation at the earth's surface exceed annual water gains from precipitation. Areas with a semiarid climatic regime are characterized by vegetation called steppe, or shortgrass prairie, and semidesert. Typical steppe vegetation consists of numerous species of short grasses that usually grow in sparsely distributed bunches. Scattered shrubs and low trees sometimes grow in the steppe; all gradations of cover are present, from semidesert to woodland. Because ground cover is generally sparse, much soil is exposed. Buffalo grass is typical of the American steppe; other typical plants are the sunflower and locoweed.

The semidesert cover is a xerophytic (plants that are structurally adapted for life and growth with a limited water supply) shrub vegetation accompanied by a poorly developed herbaceous layer. Trees are generally absent. An example of semidesert cover is the sagebrush vegetation of the middle and southern Rocky Mountain region and the Colorado Plateau. On the Colorado Plateau there is pinyon-juniper woodland. On the eastern side of Texas, the grasslands grade into either savanna woodland or semideserts, which are composed of xerophytic shrubs and trees. The climate becomes semiarid-subtropical allowing for the presence of cactus plants.

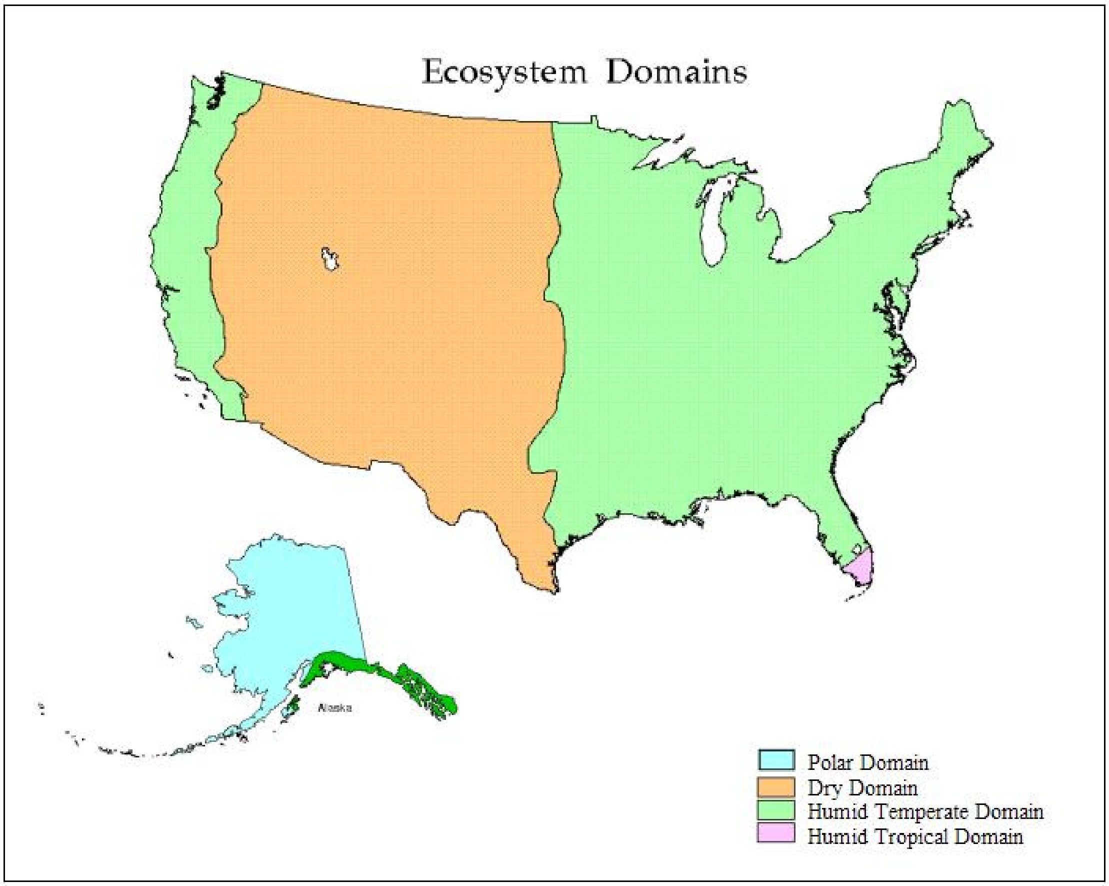

Figure 3-26. Ecological Domains of the Continental United States

3.5.1.3 Humid Tropical Domain

The humid tropical domain is restricted to the southern end of Florida. The climate is largely controlled by equatorial and tropical air masses. The average temperature for each month of the year is above 64°F (18°C) and there is no distinctive winter season. Average annual rainfall is heavy and exceeds annual evaporation.

Alternating wet and dry seasons result in the growth of distinctive vegetation known generally as tropical savanna, characterized by open expanses of tall grasses interspersed with hardy, drought-resistant shrubs and trees. Some areas have savanna woodland, monsoon forest, thornbush, and tropical scrub. In the dry season, grasses wither into straw and many tree species shed their leaves. Other trees and shrubs have thorns and small or hard leathery leaves that resist loss of water.

3.5.1.4 Polar Domain

Located at high latitudes of Alaska, the climate in the polar domain is controlled chiefly by polar and arctic air masses which are characterized by low temperatures, severe winters, and small amounts of precipitation, most of which fall in the summer months. In the northern part of Alaska the tundra is characterized by grasses, sedges, lichens, and willow shrubs. Moving southward, the vegetation changes into birch-lichen woodland, and then into needleleaf forest. In some places, a distinct tree line separates forest from tundra. South of the tundra, the sub-arctic climate zone coincides with a great belt of needleleaf forest, often referred to as boreal forest, and with the open lichen woodland known as taiga where most trees are small and therefore are valued more as pulpwood rather than lumber.

3.5.2 Wildlife

The distribution of wildlife in the U.S. is dependant, to a large extent, on the climate of the different ecoregions. The following paragraphs summarize the types of wildlife in each of the four ecological domains (USFS, 2004).

3.5.2.1 Humid Temperate Domain

Wildlife in this domain is quite varied. Some of the more important mammals include the whitetail deer, black bear, bobcat, gray fox, raccoon, gray squirrel, fox squirrel, and eastern chipmunk. The black bear occurs quite commonly in the Appalachians and surrounding areas. Whitetail deer are very common. The mink and river otter are indicative of the riverine forests primarily in the northern Midwest region of the country.

3.5.2.2 Dry Domain

This domain is home to many large mammals, some of the more common ones include elk, dear, bighorn sheep, mountain lion, bobcat, and black bear. Grizzly bear and moose inhabit the northern portions of this domain. Mule deer and whitetail deer are common, especially where brush cover is available along stream courses. Sagebrush shrub lands provide habitat for pronghorn antelope and whitetail prairie dog. Beaver and muskrat inhabit many of the lakes and streams.

3.5.2.3 Humid Tropical Domain

Common mammals indicative of this domain include whitetail deer, Florida panther, black bear, raccoon, bobcat, opossum, skunk, various bats, marsh and swamp rabbits, cotton rat, and fox squirrel. Manatees inhabit estuaries and interlacing channels.

3.5.2.4 Polar Domain

The upland and coastal areas of this domain supports a variety of wildlife, such as brown and black bear, wolf, wolverine, coyote, caribou, reindeer, snowshoe hare, red fox, lynx, beaver, moose, squirrels, mice, weasel, mink, and marten. Along the northern Bering Sea coast, polar bear, walrus, and arctic fox are occasionally found.

The Brooks Range is an important big-game area in Alaska, supporting brown and black bear, wolf, wolverine, caribou, and Dall sheep. Smaller mammals include marmot, red and arctic fox, ground squirrel, lemming, and pika.

The spruce-hardwood forests found in this domain provide excellent habitat for furbearers and other mammals. Brush zones and immature forests recovering from fires furnish especially good browse for moose. Common game animals in addition to moose include black and brown bear, wolf, wolverine, and caribou. Smaller mammals include lynx, red fox, beaver, mink, muskrat, weasel, river otter, marten, red and northern flying squirrel, and deer mouse.

3.5.3 Aquatic Habitat

The continental U.S., including Alaska contains a large variety of aquatic habitats, which in turn support a wide diversity of aquatic biota. There are 3.5 million miles of streams (approximately two thirds perennial), 41 million acres of lakes and reservoirs, 34,400 square miles of estuaries (excluding Alaska) in the U.S. (Loftus and Flather, 2000). The 191 million acres of National Forest System lands contain 128,000 miles of fishable streams and rivers, over 2.2 million acres of lakes, ponds and reservoirs, and 12,500 miles of coast and shoreline (Maharaj and Carpenter, 1999). The BLM manages over 168,000 miles of streams and more than 2.5 million acres of lakes and reservoirs (Sport Fishing Institute, 1993). Other federal agencies manage lesser amounts of waters. In terms of water quality, 70 percent of the nation's assessed river miles, lake acres, and estuarine area (in square miles) can support the "aquatic life use" designated under the Clean Water Act (EPA, 1996).

There are approximately 800 freshwater fish species in the U.S. (SAMAB, 1996). Habitats include small desert springs in the southwest that support unique and endemic fish species such as the desert pupfish; the blue ribbon trout waters of the Colorado, Green, and Snake Rivers; the salmon rivers of California, Oregon, and Washington, as well as thousands of lakes and reservoirs.

Sport fish throughout the U.S. include a variety of species, such as trout, salmon, catfish, sunfish, including various species of bass, suckers, perch, walleye, and pike. Non-sport fish include numerous species of minnows, shiners, dace, and other species. In addition to the fish, the aquatic habitats also support a tremendous variety of aquatic invertebrates, including mollusks, crustaceans, and insects.

3.5.3.1 Wetlands

Wetlands are considered to be a valuable ecological resource because of their important role in providing fish and wildlife habitat, maintaining water quality and flood control. In the past, wetlands were considered low value land that impeded commercial land development. It wasn't until relatively recent that the true value of wetlands was understood. Characteristics and functions of wetlands (Kusler, 1983) include:

- Isolated Wetlands
  - Waterfowl feeding and nesting habitat
  - Habitat for both upland and wetland species of wildlife
  - Floodwater retention area
  - Sediment and nutrient retention area
  - Area of special scenic beauty
- Lake Margin Wetlands
  - Those listed for "isolated wetlands"
  - Removal of sediment and nutrients from inflowing waters
  - Fish spawning area

- Riverine Wetlands
  - Those listed for "isolated wetlands"
  - Sediment control, stabilization of river banks
  - Flood conveyance area
- Estuarine and Coastal Wetlands
  - Those listed for "isolated wetlands"
  - Fish and shellfish habitat and spawning areas
  - Nutrient source for marine fisheries
  - Protection from erosion and storm surges
- Barrier Island Wetlands
  - Habitat for dune-associated plant and animal species
  - Protection of backlying lands from high-energy waves
  - Scenic beauty

The total wetland area present in the Continental U.S. is 274,000,000 acres (112,000,000 ha), which represents approximately 12 percent of the total surface area (Dahl, 1990). Wetlands throughout the U.S. have experienced a major decline in abundance because of human disturbance. From the 1780s to the 1980s, 53 percent of the total acreage of wetlands in the continental U.S., excluding Alaska, has been lost (Dahl, 1990). Wetland area and historic losses for each state are listed in Table 3-8.

Table 3-8. Wetlands by State

State	Wetland Area	Percent of Surface Area	Wetland Loss (%) 1780s to 1980s
Alabama	3,783,800	11.5	50
Alaska	170,000,000	45.3	50
Arizona	600,000	<1	36
Arkansas	2,763,600	8.1	72
California	454,000	<1	91
Colorado	1,000,000	1.5	50
Connecticut	172,500	5.4	50
Delaware	223,000	16.9	54
Florida	11,038,300	29.5	46
Georgia	5,298,200	14.1	23
Hawaii	51,800	1.3	12
Idaho	385,700	<1	56
Illinois	1,254,500	3.5	85
Indiana	750,633	3.2	56
Iowa	421,900	1.2	89
Kansas	435,400	0.8	48
Kentucky	300,000	1.2	81
Louisiana	8,784,200	28.3	46

State	Wetland Area	Percent of Surface Area	Wetland Loss (%) 1780s to 1980s
Maine	5,199,200	24.5	20
Maryland	440,000	6.5	73
Massachusetts	588,486	11.1	28
Michigan	5,583,400	15	50
Minnesota	8,700,000	16.2	42
Mississippi	4,067,000	13.3	59
Missouri	5,583,400	1.4	50
Montana	840,298	<1	27
Nebraska	1,905,500	3.9	35
Nevada	236,349	<1	52
New Hampshire	200,000	3.4	9
New Jersey	915,960	18.3	39
New Mexico	481,900	<1	33
New York	1,025,000	3.2	60
North Carolina	5,689,500	16.9	49
North Dakota	2,490,000	5.5	49
Ohio	482,800	1.8	90
Oklahoma	949,700	2.1	67
Oregon	1,393,875	2.2	38
Pennsylvania	499,014	1.7	56
Rhode Island	65,154	8.4	37
South Carolina	4,659,000	23.4	27
South Dakota	1,780,000	3.6	35
Tennessee	787,000	2.9	59
Texas	7,612,412	4.4	52
Utah	558,000	1.0	30
Vermont	220,000	3.6	35
Virginia	1,074,613	4.1	42
Washington	938,000	2.2	31
West Virginia	102,000	<1	24
Wisconsin	5,331,392	14.8	46
Wyoming	1,250,000	2.0	38

Source: Dahl, 1990.

3.5.4 Threatened and Endangered Species

Animals, birds, fish, plants, or other living organisms in jeopardy of extinction by human-produced or natural changes in their environment are considered threatened or endangered. Requirements for declaring species threatened or endangered are contained in the 1973 Endangered Species Act (ESA). This Act protects animal and plant species currently in danger of extinction (endangered) and those that may become endangered in the foreseeable future (threatened). The Act provides for the conservation of ecosystems upon which threatened and endangered species of fish, wildlife, and plants depend, both through federal action and by encouraging the establishment of state programs. Section 7 of this act requires federal agencies to ensure that all federally associated activities within the U.S. do not harm the continued existence of threatened or endangered species or designated areas (critical habitats) important in conserving those species.

3.5.4.1 Federally Listed Species

The ESA was passed in 1973 to address the decline of fish, wildlife, and plant species in the U.S. and throughout the world. The purpose of the ESA is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species (ESA, 1973; Section 2). The law is administered by the U.S Fish and Wildlife Service (USFWS) and the Commerce Department's National Marine Fisheries Service (NMFS). The USFWS has primary responsibility for terrestrial and freshwater organisms, while the NMFS is primarily responsible for marine species such as salmon and whales.

Under the law, species may be listed as either "endangered" or "threatened." The ESA defines an endangered species as any species that is in danger of extinction throughout all or a significant portion of its range (ESA, 1973; Section 3(6)). A threatened species is one that is likely to become an endangered species within the foreseeable future throughout all or a significant part of its range (ESA, 1973; Section 3(20)). All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened. The ESA also affords protection of "critical habitat" for threatened and endangered species. Critical habitat is defined as the specific areas within the geographical area occupied by the species at the time it is listed, on which are found physical or biological features essential to the conservation of the species and which may require special management considerations or protection (ESA, 1973; Section 3(5)(A and B)). Except when designated by the Secretary of the Interior, critical habitat does not include the entire geographical area that can be occupied by the threatened or endangered species (ESA, 1973; Section 3(5)(C)).

Some species may also be candidates for listing (ESA, 1973; Section 6(d)(1) and Section 4(b)(3)). The USFWS defines proposed species as any species that is proposed in the Federal Register to be listed under Section 4 of the ESA; while candidate species are those for which the USFWS has sufficient information on their biological status and threats to propose them for listing as endangered or threatened under the ESA, but for which development of a listing regulation is precluded by other higher priority listing activities (USFWS, 2004a). The NMFS defines candidate species as those proposed for listing as either threatened or endangered or whose status is of concern, but for which more information is needed before they can be proposed for listing. Candidate species receive no statutory protection under the ESA, but by definition these species may warrant future protection under the ESA. Currently, 1,265 plant and animal species are listed as either threatened or endangered under the ESA (USFWS, 2004b).

3.5.4.2 State Listed Species

Each state has species that are identified as protected. There is great variation in the state programs for protection of species of concern. Some species are listed per a specific definition and afforded protection and/or management under a state regulation. Other species may be included on a watch list. The distribution and abundance of these species may be tracked by organizations, such as the state Natural Heritage Program. State protected species that may be affected by a specific carbon sequestration project would depend upon the location of that particular project, and will be addressed in site-specific environmental analyses.

Table 3-9 presents the number of endangered and threatened species in the U.S. and species with designated critical habitat. A total of 518 animals and 746 plants are currently protected by the ESA. Critical habitat has been designated for 162 animals and 310 plants. In addition, there are 135 animal and 143 plants that are candidates for protection under the ESA (USFWS, 2004a).

The USFWS designated the bald eagle (*Haliaeetus leucocephalus*) as threatened on March 11, 1967. The current range of the bald eagle includes all of the conterminous U.S. and Alaska. The bald eagle is especially common in areas with large expanses of aquatic habitat, including Florida, Maine, the Chesapeake Bay, the Great Lakes and lake regions located in northern California, Oregon, Washington, and Alaska. The bald eagle is still susceptible to a number of threats, particularly environmental contaminants and excessive disturbance by humans (Buehler, 2000).

Table 3-9. Number of Endangered and Threatened Species in the U.S.

Taxonomic Group	Endangered	Threatened	Total Species	Species with Critical Habitat
Mammals	69	9	78	18
Birds	77	13	90	20
Reptiles	14	22	36	15
Amphibians	11	10	21	5
Fish	71	43	114	58
Clams	62	8	70	18
Snails	21	11	32	2
Insects	35	9	44	12
Arachnids	12	0	12	6
Crustaceans	18	3	21	8
Animal Subtotal	390	128	518	162
Flowering Plants	571	144	715	298
Conifers and Cycads	2	1	3	0
Ferns and Allies	24	2	26	12
Lichens	2	0	2	0
Plant Subtotal	599	147	746	310
Total	989	275	1264	472

** As designated in the Code of Federal Regulations (50CFR Part 17.95 and 17.96 and 226). As of November 22, 2004.*

Source: USFWS, 2004a.

3.6 CULTURAL RESOURCES

This section describes cultural resources that may be affected by carbon sequestration projects. For the purposes of this section, cultural resources generally include paleontological, archaeological and historic resources. This section provides information on the definition of cultural resources; relevant federal laws and regulatory requirements; DOE directives, policies and guidance; a summary of the national context; a summary of each regional context; and a summary of Native American population.

3.6.1 Definition of Cultural Resources

Cultural resources include prehistoric and historic districts, sites, structures, artifacts, and any other physical evidence of human activities considered important to a culture, subculture, or community, for scientific, traditional, religious, or other reasons. Cultural resources can be divided into three major categories: prehistoric and historic archaeological resources, historic buildings and structures, and traditional cultural properties. Paleontological resources are also considered under NEPA.

Cultural resources are defined as historic properties covered by the National Historic Preservation Act (NHPA); as cultural items covered by the Native American Graves Protection and Repatriation Act (NAGPRA); as archaeological resources covered by the Archeological and Historic Preservation Act (ARPA); as sacred sites (to which access is provided) under the American Indian Religious Freedom Act (AIRFA) in Executive Order 13007; as collections and associated records covered by 36 CFR Part 79, Curation of Federally Owned and Administered Collections; and as paleontological specimens (i.e., fossils) covered by the Antiquities Act and, if found in association with archeological resources, by ARPA. A summary of cultural resource terms in provided in Table 3-10.

Table 3-10. Cultural Resources Terms

Prehistoric and Historic Resources. These resources are locations where human activity measurably altered the earth or left deposits of physical remains (e.g., arrowheads or pottery). Prehistoric resources are physical properties that remain from human activities that predate written records; they range from scatterings of a few artifacts to village sites and rock art that predate written records in a region. Historic archaeological resources include remains of structures, roads, fences, trails, dumps, battlegrounds, mines, and a variety of other features. Historic resources consist of physical properties that postdate the existence of written records. In the U.S., historic resources are generally considered to be those that date no earlier than 1492.

Historic Properties. Historic properties can include buildings, sites, structures, objects, and districts. Properties considered significant are usually 50 years old or older. There are exceptions, however, such as, properties that meet significance criteria.

Historic Buildings and Structures. These include standing buildings, dams, canals, bridges, and other structures of historic or aesthetic significance. In general, architectural resources must be more than 50 years old to be considered for protection under laws protecting cultural resources.

Traditional Cultural Properties. These resources can include archaeological resources, buildings, neighborhoods, prominent topographic features, habitats, plants, animals, and minerals that Native Americans or other ethnic groups consider essential for the preservation of their traditional culture. Native American resources are sites, areas, and materials important to Native Americans for religious or heritage reasons. In addition, cultural values are placed on natural resources such as plants, which have multiple purposes within various Native American groups.

Paleontological Resources. Paleontological resources are scientifically significant physical remains, impressions, or traces, fossilized remains, specimens, deposits, and other such data from prehistoric nonhuman life, including remains of plants and animals.

(Sources: National Historic Preservation Act, Native American Graves Protection and Repatriation Act, Archeological and Historic Preservation Act, American Indian Religious Freedom Act, 36 CFR Part 79, and Antiquities Act)

3.6.2 National Context

The context of cultural resources is generally viewed in terms of the interaction over time of plants, animals, and humans with their environment. While there is evidence of abundant plant and animal life in North America going back millions of years, the composition and distribution of these plants and animals changed over long periods of time. For example, dinosaurs emerged more than 200 million years ago, were dominant for 70 million years, and around 65 million years ago became extinct along with half of all plant and animal life on earth. The fossils of dinosaurs and millions of other animals and plants have been found, including sponges, snails, shellfish, turtles, beetles, bears, worms, leaves, trees, and on and on. Based on the age of the oldest known fossils, it seems that human life began about 2.5 million years ago. *Homo* *sapiens sapiens* (fully modern man) evolved around 35,000 years ago, and then as part of a general expansion spread throughout the world. It is believed that only anatomically modern humans settled in the Americas.

The settlement of North America by modern humans may have been facilitated by climate change. There were periods where cooling (glaciation) and warming (interglacial) alternated regularly; this was caused by the changing shape of the earth's orbit, tilting of the earth's axis, and shifting times when the earth was closest to the sun (precession of the equinoxes). During several periods of climatic cooling, the Bering Strait land bridge (or Beringia) was exposed. Periods of climatic cooling include the period from 75,000 to 45,000 years ago; a lengthy period of less cold climate from about 40,000 to 25,000 years ago; and a bitterly cold period from 25,000 to around 14,000 years ago. It is believed that during these periods human migration was possible on land from Asia to North America. It is speculated that other migratory routes, such as coastal/maritime, also were possible. While research continues, the earliest secure settlement of Homo sapiens sapiens in North America was about 14,000-12,000 years ago.

3.6.2.1 Prehistoric Period Resources

Prehistoric human occupation in the U.S. is divided generally into three major periods depending on region: the Paleo-Indian Period, the Archaic Period, and, in the East and Midwest, the Woodland Period; in the West, the Formative Period, or the Fremont Period, and the Late Prehistoric Period; and in the South, the Woodland and Mississippian Periods. The most recent periods vary significantly, with each region and state defining different periods and dates. Archaeological remains or sites from each of the periods discussed below might be found, depending on topography (e.g., degree of slope, distance from fresh water) and amount of soil disturbance due to natural (e.g., erosion) or cultural (e.g., construction, agriculture, forestry, or Agency tasks) activities.

Paleo-Indian Period (ca. 12,000 B.C. to ca. [varies regionally] B.C.). The Paleo-Indian Period is the earliest evidence of humans in the New World. The climate during this time period was cooler than the present environment. Large animals, such as mammoth and extinct species of bison, flourished. Paleo-Indian peoples were nomadic hunters and gatherers who lived in small groups and ate wild plants and animals. This period is distinguished by a low population density with groups residing in seasonal or base camps; as a result, Paleo-Indian sites are rare and usually very small in size. The Paleo-Indian Period is also noted for diagnostic fluted projectile points and the exploitation of Pleistocene megafauna, such as mammoths and giant sloth.

Archaic Period (varies regionally). Archaeologists divide the Archaic Period into three time frames—Early, Middle, and Late. Between 10,000 years before the present (BP) and 5,000 BP, substantial climatic and ecological changes occurred across the North American continent. During the Archaic Period, the cold dry environment that had existed during the Paleo-Indian Period changed to a warmer and wetter environment. These changes were accompanied by a change from Paleo-Indian to Archaic traditions. Groups responded to these changes, and archaeological evidence shows increased use of the new environment. These groups lived a nomadic life, moving seasonally to make use of the variety of flora and fauna available in different locations or ecological zones at different times of the year. Mammals included mountain sheep, deer, and smaller mammals and birds. Milling stones and items made of wood, bark, and fiber are common during this Period. During the Late Archaic Period, the ecology and climate became much the same as they are today, with a higher sea level and wetter climate than those of the previous period.

Woodland Period (varies regionally). This period is identified in the Mid-Atlantic, Northeast, Southeast, and Midwest. It is divided into three periods—the Early Woodland, the Middle Woodland, and the Late Woodland. The Woodland Period is characterized by the first appearance of true-fired ceramics. Food storage pits provide archaeological evidence that the population became more sedentary during this period, and plant remains indicate that plants were domesticated during this period.

Mississippian Period (varies regionally). This period is identified in the Southeast by the presence of certain ceramic types and stone tools, large-scale earthworks, and the remains of villages.

Late Prehistoric Period (varies regionally). This period is identified by archaeologists in the Southwest, particularly Texas and Colorado. During this period, people changed from somewhat egalitarian, nomadic hunter-gatherers relying on wild plants and animals to people who practiced agriculture and lived in more hierarchical chiefdom societies. Agricultural remains include maize; other remains include ceramic pottery, storage pits, hearths, and small triangular projectile points.

Formative Stage and Post-Formative Stage (varies regionally). These stages are identified in some areas of the West. During the Formative Stage, agriculture was introduced into the region. Groups became more sedentary, living longer in one location. They lived in small villages, and remains of their pit houses and masonry structures can be identified archaeologically. These stages are characterized archaeologically by the presence of ground stone artifacts, used for processing food; specific ceramic types; and remains of structures, including pit houses. During the Post-Formative Stage, historically known Native American groups lived in the West.

Fremont Period (varies regionally). This period is recognized in Colorado and in the Great Basin. It is largely defined by farming (i.e., squash, sunflower, beans, and maize) but also included full- and part-time farmers and foragers, depending on location and season. The Period is also known for the appearance of semisubterranean structures and storage pits, and aboveground granaries.

3.6.2.2 Historic Period Resources

3.6.2.2.1 Contact Period

Historic Native Americans lived throughout the U.S. during the period from 1492 (landfall of Columbus) onward. Contact between the different cultures (European, African, and Native American) varied from region to region. The earliest contacts were along the eastern and western coasts, where the Spanish first landed.

In the Southeast, first contact was made when Hernando de Soto and his men explored that area between 1540 and 1542. They traveled from present-day Tampa Bay through Florida, Georgia, Tennessee, Alabama, Mississippi, and Arkansas, encountering Mississippian peoples.

The interior parts of the country did not experience contact until centuries later; in the West, earliest contact among Native American groups and people of European and African descent was made by Lewis and Clark (1804-1806), as well as by French and English fur trappers and French Catholic missionaries (for example, in the upper Midwest and Northwest). Native American groups experienced extreme population decline and dislocation during this period, as a result of warfare and disease. The Contact Period ends at different times in different regions. Contact Period cultural resources can include archaeological sites, objects, and standing structures or remains of structures.

3.6.2.2.2 Historic Period

The start of this period varies from region to region, and the period continues until the present time. Each state has a set of historic contexts, such as homesteading era, railroading era, rural agricultural era, on World War II era. Each of these has been defined by the SHPO and is used as a context for evaluating the NRHP eligibility and significance of archaeological sites, objects, and standing structures. Historic Period sites can include archaeological sites, objects, standing structures or remains of structures, roads, or railroad tracks. In most cases, the resource must be at least 50 years old; however, some exceptions, such as structures or scientific equipment considered significant might be NRHP-eligible.

3.6.3 Regional Context

At time of contact with European culture, there were a great variety of Native American groups in North America. For example, linguists believe that at least 200 languages were spoken in North America. In light of this complex situation, a number of ways have been devised to organize and analyze North American Native American cultural resources. These consider factors such as geography, environment, language, population density, religion, shelter, transportation, subsistence patterns, and sociopolitical organization. The most common approach divides U.S into 8 regional cultural areas (Waldman, Atlas of the North American Indian, 2000):

- Northeast: Includes northeastern states as far west and south as eastern Minnesota, western Illinois, eastern Missouri, northern Tennessee and northern Virginia.
- Southeast: Includes Virginia, North Carolina, South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, southern Arkansas and eastern Texas.
- Southwest: Includes southern New Mexico, western Texas, and southern Arizona.
- Great Basin: Includes western Colorado, Utah, southern Idaho, southeastern Oregon, Nevada, northern Arizona and northern New Mexico.
- California: coastal California
- Northwest Coast: western Washington, western Oregon, northern California.
- Arctic and Subartic: Alaska.
- Plateau: Includes northern Idaho, eastern Washington, and eastern Oregon.
- Great Plains: Includes western Minnesota, Iowa, western Missouri, Arkansas, Oklahoma, central Texas, Kansas, Nebraska, South Dakota, North Dakota, Montana, eastern Wyoming, and eastern Colorado.

These areas generally represent patterns of Native American life just before contact with European culture. Two factors, however, should be noted. First, while they are useful as a general analytical approach, they should not be taken to imply an internal cultural homogeneity within each area.

3.6.3.1 Northeast Cultural Area

This area loosely comprises the area from New England to the western Illinois border (plus most of Wisconsin, the northeast corner of Minnesota, a wedge in middle Tennessee, all of coastal Virginia, and the northern half of coastal North Carolina). Despite the physiographic diversity of the Northeast cultural area, the forest, both deciduous and coniferous, is the one constant. The Northeast tribes at the time of contact were inheritors of earlier traditions, sometimes grouped together as “Woodland.” Tribes or groups were small and widely scattered in small bands.

The principal language families in the Northeast Cultural Area were the Algonquians and Iroquois. It is thought that the Iroquoian tribes were more recent arrivals in the region than the Algonquians and that they probably migrated from the south. Both the Iroquoian and Algonquians had strong tribal identities that went beyond the basic nuclear family. Major Native American tribes in the Iroquoian language family located included the Susquehannock while those in the Algonquian language family included the Nantocoke, Potawatomi and Menominee. The Iroquoians generally lived in communal longhouses while the Algonquians generally lived in smaller wigwams with longhouses serving as council or ceremonial buildings. The Iroquoian subsistence pattern was highly dependent on vegetable farming with the three main source of food being maize, beans and squashes.

3.6.3.2 Southeast Cultural Area.

Most Native Americans of the Southeastern cultural area made their homes in villages along river valleys. Because of the common sandy soil conditions, agricultural fields and the corresponding village site frequently changed. Cultivated corn, beans, squash, sunflowers and gourds were the major source of food, except in south Florida. Fish were plentiful, and in some areas, such as along the lower Mississippi River, fish and water fowl provided at least half the protein of the Indian's diet. The main type of architecture involved branches and vines tied over pole and frameworks, then covered with a mixture of mud plaster.

Despite similarities in lifeways throughout the area, there were many different language families at the time of European contact. These included the Muskogean, Siouan, Iroquoian, Caddoan, Timucuan and Tunican. Some people, like the Natchez, are considered direct descendants of the ancient temple mound builders of the Mississippian culture, but others were later arrivals who inhabited many of the same sites. The Southeast cultural area contained complex societies where chiefdoms were centered on a capital town containing massive earthworks in the form of mounds. For example, Moundville was a chiefdom (located about 60 miles from present day Birmingham, AL) on the northeastern edge of the Muskogee territory; within its 300 acres were 20 major mounds of roughly pyramidal shape, the largest of which was 60 feet in height.

The Southeast chiefdoms were expansive, fighting with their neighbors. Everyone with a chiefdom belonged to a clan, each associated with a tutelary spirit. The clans were matrilineal, exogamous (i.e., marriage within the clan was prohibited), and every clan spread through many villages. Chiefly office and lesser ranks were hereditary. In traditional Southeastern cultures, there were no sharp distinction between religious and medical beliefs, rituals and practices.

3.6.3.3 Southwest Cultural Area

The Southwest cultural area (sometimes characterized as Las Vegas, NV-to-Las Vegas, NM, and Durango, CO-to-Durango, Mexico) is described as an arid area with an annual average rainfall ranging from less than 20 inches to less than 4 inches. Within this area, two predominant Native American lifestyles—agrarian and nomadic—developed. The agrarian peoples included Pueblo Indians of the Rio Grande, upland and river Yuman-speakers, and the Uto-Aztecan-speaking Pima and Papago. These people were politically independent, and socially and economically self-sufficient. In fact, agriculture north of Mesoamerica reached its highest level of development in the southwest. These skilled farmers could support sizable populations in permanent villages that the Spanish termed earthen pueblos. Each Pueblo culture was a village that functioned as an autonomous political entity. The family was the cornerstone of life, religion transcended and permeated all aspects of life, and they developed an extensive native literature expressed through song, folk stories and oratory. In contrast to the agricultural basis of Pueblo life, the Athapascan Apache and Navajo, later arrivals to the region from the north, were nomadic hunters and gatherers. They supplemented their diet by raiding Pueblo and other villages for their crops. Most of the Apaches lived in small units based on extended families; local groups composed of several matri-focal extended families formed bands, the largest level of political organization. The two main types of housing were brush-covered wickiups and earth-covered hogans.

3.6.3.4 Great Basin Cultural Area

The Great Basin cultural area generally is surrounded by uplands; to the east are the Rocky Mountains, to the west are the Sierra Nevada, to the south is the Colorado Plateau, and to the north is the Columbia Plateau. The rivers and streams of the Great Basin drain from these flanking uplands into the central depression without any outlet to the ocean. Rainfall is this area is low and evaporation high. Because of the area's unique geology, waters tend to be saline. The tribes of the Great Basin were of one language family, the Uto-Aztecan. The major Native American groupings from the Great Basin cultural area included Ute and Southern Paiute. Because of meager food supplies, their major food resources were roots and seeds. People generally traveled in small family groups with minimal tribal identity and few community rites. During the spring and summer, housing consisted of temporary shelters or windbreaks made of reed mats and branches; during the winter, shelters were more substantial, some being subterranean with an opening through the mound-like roof that served as both a door and smokehole.

3.6.3.5 California Cultural Area

The California cultural area contained bountiful flora and fauna. Because of ample food sources, the California region supported the densest population north of Mescoamerica without the practice of agriculture. The basic social unit was the family with groups of families forming villages presided over by a single chief. There was a high degree of isolation among these villages with little movement of people once the group was established. At the time of European contact, more than 100 distinct dialects were spoken by native peoples. These included language families of the Hokan phylum (viz., a large division of related families of languages or linguistic stocks) in the north and coastal-central; the Penutian phylum in the north-central and north; and the Uto-Aztecan phylum in the south.

3.6.3.6 Northwest Coast Cultural Area

The Northwest Coast cultural area's temperate climate and abundant rainfall nourished a lush evergreen forested area. The forests, rivers and ocean offered plentiful fish and game. With this food source, the Native Americans of this area supported a dense population along the coast and had sufficient time to develop an affluent and high complex society. There were no large political units outside of the individual village. Villages typically were sited on narrow sand and gravel beaches of the mainland and islands or along inland rivers; houses faced the water. Totem poles were prevalent along the lower Tlingit, Haida, Tsimishian and Kwakiutl peoples. Large extended families often lived together in communal longhouses. Family ties were extremely important with people identifying closely with extended families and lineages. Among the Tlingit, Haida and Tsimishian in the Alaska panhandle, society was matrilineal, while among the Salish groups in British Columbia and Washington, inheritance came from both parents. Ceremonial gatherings, called potlatches, were important for validating tribal rank, leadership, and cultural heritage. The language families and isolates (viz., languages not related to others) were represented by two major phyla: Na-Dene (spoken by the Tlingit and Haida as well as a number of Athapascan peoples) and Penutian (spoken by such tribes as Chinook, Kalapuya, Siuslaw, Coos and Takelma).

3.6.3.7 Subartic Cultural Area

The Subartic cultural area contained scattered and few aboriginal people who had to cope with long, harsh winters as well as short summer plagued with black flies and mosquitoes. Most Subarctic peoples were nomadic hunter-gathers. They survived without agriculture, and traveled in small bands united by kinship and a common dialect. Tribal cohesion tended to be minimal; only for comparatively short periods during the summer months did these various groups rendezvous and express a form of tribal solidarity. Up to a point, emphasis was placed on personal autonomy, especially self-reliance and personal initiative. Athapascans made up the main language group in the western Subartic cultural area; these peoples lived near and were influenced by the Inuit. Subarctic Native American tribes located principally in the interior of Alaska included the Holikachuk, Ingalik, Kolchan, Tanaina, Koyukon, Tanana and Ahtna.

3.6.3.8 Artic Cultural Area

The Arctic cultural area was peopled by migrants from Siberia who came relatively late to North America, probably from 2500 to 1000 B.C. They did not travel the Bering Strait land bridge, but came by boat or by riding ice flows. As they spread across the north, three linguist groups evolved. First, the

Aleut separated from the Eskimo-Aleut stock and then the Yup'ik and Inuit-Inupiaq split. The primary means of subsistence was hunting, especially sea mammals and caribou, supplemented by fishing. They exhibited a uniformity of culture, and there was only one defined language (Eskimaleut). The cultural grouping included South, West and North Alaskan Inuit; Aleut; Saint Lawrence Island Inuit; and Mackenzie Inuit.

3.6.3.9 Plateau Cultural Area

The Plateau cultural area is flanked by the Cascades Mountains on the west, the Rocky Mountains on the east, the desert country of the Great Basin on the south, and the forest and hill country of the upper Fraser River on the north. Through fishing, hunting and gathering, the Native Americans of this region could subsist without farming. Habitations varied in style and emphasis. Villages were the main political units. The acquisition of horses, probably around the first quarter of the 18^{th} century, resulting in increased interaction with more distant tribes such as those on the Plains to the east. North of the Columbia River, the most common language family was Salishan (of uncertain phylum), with dialects spoken by tribes such as Coeur d'Alene, Flathead and Kalispel. Language families and isolates of the Penutian phylum were spoken in the south by tribes such as the Nez Perce.

3.6.3.10 Great Plains Cultural Area

This is a vast region of predominantly treeless grassland. The eastern prairies receive 20-40 inches of rainfall a year, resulting in long grass while the western high plains have 1-20 inches of rainfall and short grass. At the time of contact with European culture, most of the region's tribes were villagers and farmers, or at least semi-nomads. Early agriculturalists included the Siouan-speaking Manadan and Hidatsa, and the Caddoan-speaking Wichita and Pawnee. Other peoples entered the region at later dates because of unfavorable conditions elsewhere or to pursue buffalo herds; these included Algonquian-speaking Arapaho and Cheyenne from the northeast; the Siouan-speaking Sioux (Dakota, Lakota and Nakota), Ponca, Ioway, Omaha, Otoe, Kaw (Kansa), Missouria and Osage from the east; the Kiowa-Tanoan-speaking Kiowa from the northwest; and the Athapascan-speaking Kiowa-Apache from the southwest.

This cultural area is unique in that the typical Native American subsistence pattern and related lifeways evolved after contact with European culture. In fact, full flowering of the historic Plains culture did not occur until the acquisition of the horse from the south and the gun from the east. For example, the reintroduction of horses by the Spanish allowed for increased mobility and prowess. As a result, the former village and farming tribes of river valleys became nomadic hunters, especially of the buffalo. Bands of related families made up the Great Plains tribes. The bands lived apart most of the year, but came together for communal buffalo hunts and ceremonies in the summer. A complex intertribal trade network developed between these nomadic hunters and more sedimentary peoples. The typical dwelling was a portable cone-shaped tipee with pole frameworks covered with buffalo hides. The tipee was generally pitched with its back toward the prevailing westerly wind direction, its wide base and sloping side giving a high degree of stability.

3.6.4 American Indian Population

There are no precise figures on how many American Indians were in North America at the time of first contact with European culture. The estimate most often used for the region north of Mexico is 1 million (750,000 for what is now the U.S. and 250,000 for Canada) to 1 and 1.5 million. After European contact, not only did the patterns of American Indian population density begin to change, but the numbers declined to a low of less than 250,000 between 1890 and 1910. Since then, the American Indian population has rebounded. According to the 2000 U.S. Census, there are 2,475,956 Indians, Eskimos or Aleuts in the U.S. (0.9 percent of the total U.S. population of 281,421,906); of these, only 479,390

Indians (less than 0.2 percent of the total U.S. population) live on 314 federally recognized reservations in the U.S.

Maps of federally recognized Indian tribes and American Indian populations in the U.S. can be accessed at http://www.census.gov/geo/www/maps/aian_wall_map/aian_wall_map.htm.

The 2000 population by state of Americans Indians who live on reservations is summarized in the following Table 3-11, while Table 3-12 shows American Indian population by reservation in each applicable region. The tables show statistics only for "Indian land" classified as a reservation, pueblo, rancheria, colony, or community.

Table 3-11. Population Statistics for American Indian Reservation by State

American Indian Reservation and Off-Reservation Trust Land (Federal)	American Indian or Alaska Native
Alabama	131
Alaska	156,776
Arizona	161,284
California	15,684
Colorado	12,191
Connecticut	227
Florida	1,239
Idaho	7,306
Iowa	632
Kansas	1,358
Louisiana	822
Maine	2,005
Massachusetts	66
Michigan	5,347
Minnesota	17,171
Mississippi	4,902
Montana	22,787
Nebraska	4,343
Nevada	7,039
New Mexico	104,813
New York	7,349
North Carolina	6,665
North Dakota	18,733
Oklahoma	238,331
Oregon	5,011
Rhode Island	9
South Carolina	362
South Dakota	41,712
Texas	1,310
Utah	9,623
Washington	27,150
Wisconsin	15,557
Wyoming	6,544
TOTAL	904,479

Source: 2000 U.S. Census.

Table 3-12. Native American Population by Region and Reservation

Region and Indian Reservation (Federal)	American Indian or Alaska Native
Alabama, Poarch Creek Reservation	98
Alaska, Ahtna Alaska Native Regional Corp.	707
Alaska, Aleut ANRC	2,150
Alaska, Annette Island Reserve	1,175
Alaska, Arctic Slope ANRC	5,050
Alaska, Bering Straits ANRC	6,915
Alaska, Bristol Bay ANRC	5,336
Alaska, Calista ANRC	19,617
Alaska, Chugach ANRC	1,696
Alaska, Cook Inlet ANRC	24,923
Alaska, Doyon ANRC	11,182
Alaska, Koniag ANRC	2,028
Alaska, NANA ANRC	5,944
Alaska, Sealaska ANRC	11,320
Arizona, Cocopah Reservation	519
Arizona, Ft. Apache Reservation	11,702
Arizona, Ft. McDowell Reservation	755
Arizona, Gila River Reservation	10,353
Arizona, Havasupai Reservation	453
Arizona, Hopi Reservation	6,442
Arizona, Hualapai Reservation	1,253
Arizona, Kaibab Reservation	131
Arizona, Maricopa (Ak Chin) Reservation	652
Arizona, New Mexico, Utah, Navajo Reservation	149,423
Arizona, New Mexico, Zuni Reservation	7,426
Arizona, Pascua Yqui Reservation	3,002
Arizona, Salt Ri. Reservation	3,366
Arizona, San Carlos Reservation	8,921
Arizona, Tohono O'odham Reservation	9,417
Arizona, Tonto Apache Reservation	115
Arizona, Yavapai-Apache Reservation	650
Arizona, Yavapai-Prescott Reservation	117
Arizona-California, Ft. Yuma Reservation	1,350
California, Alturas Rancheria	2
California, Aqua Pueblo Reservation	176
California, Arizona, Ft. Mojave Reservation	360
California, Barona Reservation	357
California, Benton Maiute Reservation	39
California, Big Lagoon Rancheria	19
California, Big Pine Reservation	287
California, Big Sandy Rancheria	77
California, Big Valley Rancheria	188
California, Bishop Reservation	950
California, Blue Lake Rancheria	33
California, Bridgeport Reservation	22
California, Cabazon Reservation	15
California, Cahuilla Reservation	106

Region and Indian Reservation (Federal)	American Indian or Alaska Native
California, Campo Reservation	245
California, Ceadarville Rancheria	22
California, Chemehuevi Reservation	149
California, Cold Springs Rancheria	177
California, Colusa Rancheria	59
California, Corttina Rancheria	18
California, Coyote Valley Reservation	84
California, Dry Creek Rancheria	36
California, Elk Valley Rancheria	40
California, Enterprise Rancheria	1
California, Ft. Bidwell Reservation	101
California, Ft. Independence Reservation	41
California, Greenville Rancheria	5
California, Grindstone Rancheria	141
California, Hoopa Valley Reservation	2,230
California, Hopland Rancheria	13
California, Jackson Rancheria	0
California, Jamul Indian Village	1
California, Karuk Reservation	46
California, La Jolla Reservation	294
California, La Posta Reservation	15
California, Laytonville Rancheria	160
California, Lone Pine Reservation	131
California, Lookout Rancheria	4
California, Los Coyotes Reservation	56
California, Manchester-Point Arena Ranch	151
California, Manzanita Reservation	56
California, Mesa Grande Reservation	60
California, Middletown Rancheria	51
California, Montgomery Rancherias	3
California, Mooretown Rancheria	116
California, Morongo Reservation	543
California, North Fork Rancheria	5
California, Pala Reservation	693
California, Pauma and Yuima Reservation	158
California, Pechanga Reservation	346
California, Picayune Rancheria	15
California, Pinoleville Rancheria	92
California, Quartz Valley Reservation	44
California, Redding Rancheria	29
California, Redwood Valley Rancheria Reservation	106
California, Resighini Rancheria	36
California, Rincon Rancheria	411
California, Roaring Creek Rancheria	9
California, Robinson Rancheria	118
California, Rohnerville Rancheria	62
California, Round Valley Reservation	56
California, Rumsey Rancheria	21
California, San Manuel Reservation	41

Region and Indian Reservation (Federal)	American Indian or Alaska Native
California, San Pasqual Reservation	341
California, Santa Rosa Rancheria	426
California, Santa Rosa Reservation	56
California, Santa Ynez Reservation	83
California, Santa Ysabel Reservation	225
California, Sherwood Valley Rancheria	131
California, Shingle Springs Rancheria	18
California, Smith Ri. Rancheria	41
California, Soboda Reservation	433
California, Stewarts Point Rancheria	55
California, Sulphur Bank Rancheria	53
California, Susanville Rancheria	220
California, Sycuan Reservation	21
California, Table Bluff Reservation	59
California, Table Mt. Rancheria	1
California, Torres-Martinez Reservation	195
California, Trinidad Rancheria	42
California, Tule Ri. Reservation	495
California, Tuolumne Rancheria	129
California, Upper Lake Rancheria	45
California, Viejas Reservation	146
California, Woodfords Comm	164
California, XL Ranch	11
California, Yurok Reservation	499
California, Arizona, Colorado River Reservation	2,292
Colorado, Southern Ute Reservation	10,805
Colorado, Utah, Ute Mt. Reservation	1,658
Florida, Big Cypress Reservation	110
Florida, Brighton Reservation	449
Florida, Hollywood Reservation	538
Florida, Immokalee Reservation	142
Idaho, Ft. Hall Reservation	3,648
Idaho, Kootenai Reservation	71
Idaho, Nez Perce Reservation	2,101
Iowa, Nebraska, Omaha Reservation	2,302
Iowa, Sac and Fox/Meskwaki Reservation	579
Kansas, Kickapoo (KS) Reservation	714
Kansas, Nebraska, Sac and Fox Reservation	49
Kansas, Prairie Ban Potawatomi Reservation	518
Louisiana, Chitimacha Reservation	285
Louisiana, Coushatta Reservation	20
Louisiana, Tunica-Biloxi Reservation	561
Michigan, Bay Mills Reservation	472
Michigan, Hannahville Comm	253
Michigan, Huron Potawatomi Reservation	9
Michigan, Isabella Reservation	1,397
Michigan, Lac Vieux Desert Reservation	113
Michigan, L'Anse Reservation	850
Michigan, Sault Ste. Marie Reservation	290

Region and Indian Reservation (Federal)	American Indian or Alaska Native
Minnesota, Bois Forte Reservation	464
Minnesota, Fond du Lac Reservation	1,353
Minnesota, Grand Portage Reservation	322
Minnesota, Leech Lake Reservation	4,561
Minnesota, Lower Sioux Reservation	294
Minnesota, Mille Lacs Reservation	1,034
Minnesota, Prairie Island Indian Community	166
Minnesota, Red Lake Reservation	5,071
Minnesota, Sandy Lake Reservation	66
Minnesota, Shakopee Mdeweak Sioux Comm	175
Minnesota, Upper Sioux Reservation	5,601
Minnesota, White Earth Reservation	3,374
Mississippi, Choctaw Reservation	4,087
Montana, Crow Reservation	5,165
Montana, Flathead Reservation	6,999
Montana, Ft. Belknap Reservation	2,790
Montana, Ft. Peck Reservation	6,391
Montana, Northern Cheyenne Reservation	4,029
Montana, Rocky Boy's Reservation	1,542
Kansas, Nebraska, Iowa Reservation	99
Nebraska, Santee Reservation	563
Nebraska, Winnebago Reservation	1,447
Nevada, Battle Mt. Reservation	112
Nevada, Campbell Ranch	207
Nevada, Carson Colony	241
Nevada, Dresslerville Colony	287
Nevada, Duckwater Reservation	116
Nevada, Elko Colony	627
Nevada, Ely Reservation	87
Nevada, Fallon Paiute-Shoshone Colony	105
Nevada, Fallon Paiute-Shoshone Reservation	534
Nevada, Idaho, Duck Valley Reservation	998
Nevada, Las Vegas Colony	100
Nevada, Lovelock Colony	86
Nevada, Moapa Ri. Reservation	165
Nevada, Oregon, Ft. McDermitt Reservation	301
Nevada, Oregon, Ft. McDermitt Reservation	301
Nevada, Pyramid Lake Reservation	1,221
Nevada, Reno-Sparks Colony	830
Nevada, South Fork Reservation	77
Nevada, Stewart Comm	150
Nevada, Summit Lake Re	11
Nevada, Utah, Goshute Reservation	97
Nevada, Walker Ri. Reservation	667
Nevada, Wells Colony	39
Nevada, Winnemucca Colony	44
Nevada, Yerington Colony	124
Nevada, Yomba Reservation	89
New Mexico, Acoma Pueblo	2,723

Region and Indian Reservation (Federal)	American Indian or Alaska Native
New Mexico, Cochiti Pueblo	695
New Mexico, Isleta Pueblo	2,675
New Mexico, Jemez Pueblo	1,941
New Mexico, Jicarilla Apache Reservation	2,475
New Mexico, Laguna Pueblo	3,669
New Mexico, Mescalero Reservation	2,888
New Mexico, Nambe Pueblo	455
New Mexico, Picuris Pueblo	166
New Mexico, Pojoaque Pueblo	264
New Mexico, San Felipe Pueblo	2,465
New Mexico,San Ildefonso Pueblo	528
New Mexico,San Juan Pueblo	1,328
New Mexico,Sandia Pueblo	500
New Mexico,Santa Ana Pueblo	473
New Mexico,Santa Clara Pueblo	1,329
New Mexico,Santo Domingo Pueblo	3,085
New Mexico,Taos Pueblo	1,331
New Mexico,Tesuque Pueblo	355
New Mexico, Zia Pueblo	645
North Carolina, Eastern Cherokee Reservation	6,665
North Dakota, Ft. Berthold Reservation	3,986
North Dakota, South Dakota, Standing Rock Reservation	5,964
North Dakota, Spirit Lake Reservation	3,317
North Dakota, Turtle Mt. Reservation	47
Oklahoma, Osage Reservation	6,410
Oregon, Burns Paiute Colony	148
Oregon, Celilo Village	39
Oregon, Coos, Lo. Umpqua, Siuslaw Reservation	10
Oregon, Coquille Reservation	128
Oregon, Cow Creek Reservation	5
Oregon, Grand Ronde Comm	30
Oregon, Klamath Reservation	4
Oregon, Siletz Reservation	182
Oregon, Umatilla Reservation	1,427
Oregon, Warm Springs Reservation	3,038
South Carolina, Catawba Reservation	362
South Dakota, Cheyenne River Reservation	6,249
South Dakota, Crow Creek Reservation	1,936
South Dakota, Flandreau Reservation	326
South Dakota, Lower Brule Reservation	1,237
South Dakota, North Dakota, Lake Traverse Reservation	3,453
South Dakota, Pine Ridge Reservation	12,985
South Dakota, Rosebud Reservation	7,747
South Dakota, Yankton Reservation	2,633
Texas, Alabama-Coushatta Reservation	480
Texas, Kickapoo (TX) Reservation	420
Texas, Ysleta Del Sur Pueblo	410

Region and Indian Reservation (Federal)	American Indian or Alaska Native
Utah, Paiute (UT) Reservation	250
Utah, Skull Valley Reservation	30
Utah, Uintah and Ouray Reservation	2,780
Washington, Chehalis Reservation	388
Washington, Colville Reservation	4,528
Washington, Hoh Reservation	81
Washington, Jamestown S'Klallam Reservation	0
Washington, Kalispel Reservation	180
Washington, Lower Elwha Reservation	208
Washington, Lummi Reservation	2,114
Washington, Makah Reservation	1,083
Washington, Muckleshoot Reservation	1,033
Washington, Nisqually Reservation	357
Washington, Port Gamble Reservation	505
Washington, Port Madison Reservation	497
Washington, Puyallup Reservation	1,324
Washington, Quainalt Reservation	1,051
Washington, Quileute Reservation	307
Washington, Sauk-Suiattle Reservation	35
Washington, Shoalwater Bay Reservation	44
Washington, Skokomish Reservation	510
Washington, Spokane Reservation	1,533
Washington, Stillaguamish Reservation	26
Washington, Swinomish Reservation	617
Washington, Tulalip Reservation	2,049
Washington, Upper Skagit Reservation	180
Washington, Yakama Reservation	7,289
Wisconsin, Bad River Reservation	1,096
Wisconsin, Forest Co. Potawatomi Comm	475
Wisconsin, Ho-Chunk Reservation	574
Wisconsin, Lac Courte Oreilles Reservation	2,147
Wisconsin, Lac du Flambeau Reservation	1,778
Wisconsin, Menominee Reservation	3,061
Wisconsin, Oneida (WI) Reservation	3,288
Wisconsin, Red Cliff Reservation	928
Wisconsin, Sokaogon Chippewa Comm	255
Wisconsin, St. Croix Reservation	443
Wisconsin, Stockbridge-Munsee Comm	796
Wyoming, Wind River Reservation	6,542

Source: 2000 U.S. Census.

3.7 AESTHETIC AND SCENIC RESOURCES

This section describes the aesthetic and scenic resources that may be affected by carbon sequestration projects.

In this document, the term "aesthetics" is defined as the study of beauty and of judgments concerning beauty. The term "scenic" pertains to natural or natural-appearing landscapes and conditions that afford pleasant views of landscape attributes or positive cultural attributes. Principal aesthetic and scenic resources include National Parks, forests, nature areas, and other resources designated for preservation and management by the Federal government. Additional aesthetic and scenic resources include parks, forests, nature areas, and other resources designated for preservation and management by states and local jurisdictions. Visibility is an important park resource and one of the major reasons people visit national parks. "Visibility is made up of two main components: (1) how far you can see a distant object, and (2) how clearly you can see a distant object." The largest threat to visibility is haze. Haze is caused by particulate matter (PM), which is "made up of tiny particles of soot, dust, and other materials from diesel engines, power plants, wood stoves, and dirt roads." The PM scatters and absorbs light that affects the clarity of objects and renders distant views unclear (NPS, 2005)

3.7.1 National Context

The National Park System (NPS) encompasses approximately 84.5 million acres, of which more than 4.2 million acres remain in private ownership. Table 3-13 summarizes the NPS aesthetic and scenic resources for the entire country (NPS, 2003). In this table and throughout this section, the following definitions apply:

- "International Historic Sites" include all international areas containing a single historical feature upon which the site is based.
- "National Battlefield Parks, National Battlefield Sites, National Battlefields, and National Military Parks" include areas containing historical military lands.
- "National Historic Sites" include all national areas containing a single historical feature upon which the site is based.
- "National Historical Parks" include historic parks that extend beyond single properties or buildings.
- "National Lakeshores" are all located on the Great Lakes and closely parallel the seashores in character and use.
- "National Memorials" include areas that are commemorative of a historic person or event.
- "National Monuments" include landmarks, structures, and other objects of historic or scientific interest situated on government lands.
- "National Parks" include large natural places that prohibit hunting, mining, and consumptive activities and which have a wide variety of attributes that may or may not include significant historic assets.
- "National Preserves" include areas of natural or scientific significance within the boundaries of other park systems.
- "National Recreation Areas" include water and lands that combine scarce open spaces with the preservation of significant historic resources and natural areas in order to provide recreation for large numbers of people.

- "Natural Reserves" include areas having characteristics of National Parks but which permit public hunting, trapping, oil/gas exploration and extraction.
- "National Rivers" include national rivers (wild rivers and scenic rivers are categorized separately).
- "National Scenic Trail" includes over 3,600 miles of linear parklands authorized under the National Trails System Act of 1968.
- "National Seashores" include ten national seashores along the Atlantic, Gulf, and Pacific coasts.
- "National Wild and Scenic Rivers" include rivers designated under the Wild and Scenic Rivers Act of 1968.
- "Parks (other)" includes other national land areas that bear unique titles.
- "Parkways" includes roadways and parkland paralleling a roadway intended for scenic motoring (NPS, 2002).

Additionally, there are numerous state parks, wildlife refuge areas, wildlife management areas, wilderness areas, trails, rivers, lakes and shores, scenic byways, archeological sites, recreation areas, and historic sites that further contribute to the scenic and aesthetic resources of the regions.

Table 3-13. National Park Service Aesthetic and Scenic Resources (2003) in the U.S.

Aesthetic and Scenic Resources	Entire United States (acres)
International Historic Sites	45
National Battlefield Parks	10,472
National Battlefield Sites	1
National Battlefields	13,405
National Historic Sites	37,657
National Historical Parks	167,102
National Lakeshores	228,867
National Memorials	9,100
National Military Parks	40,759
National Monuments	2,335,063
National Parks	51,888,804
National Preserves	24,153,467
National Recreation Areas	3,692,557
National Reserves	33,431
National Rivers	426,353
National Scenic Trails	236,573
National Seashores	595,046
National Wild & Scenic Rivers	314,130
Parks (Other)	39,622
Parkways	175,786
Total	84,238,386

Source: NPS, 2003.

3.7.2 State Resources

A summary of National aesthetic and scenic resources by state is provided in Table 3-14. Additional National Park and other scenic resources that cross state boundaries are listed in Table 3-15. Extent of State forests and parks by state is provided in Table 3-16.

Table 3-14. National Park Service Aesthetic and Scenic Resources (2005)

State	Acreage	Annual Visitors
Alabama	16,131	747,617
Alaska	54,625,602	2,359,084
Arizona	2,010,561	10,799,429
Arkansas	104,928	2,546,209
California	4,831,706	33,400,604
Colorado	516,553	5,352,839
Connecticut	74	11,129
Delaware	0	0
Florida	2,571,213	7,794,294
Georgia	55,785	5,652,269
Hawaii	364,999	5,415,722
Idaho	735,753	446,507
Illinois	13	419,552
Indiana	15,293	2,402,913
Iowa	2,713	240,760
Kansas	11,792	121,419
Kentucky	53,175	3,361,946
Louisiana	21,128	498,446
Maine	47,435	2,051,484
Maryland	17,365	3,242,054
Massachusetts	46,376	9,088,046
Michigan	718,186	1,716,599
Minnesota	272,967	628,087
Mississippi	1,902	5,743,683
Missouri	83,376	4,815,314
Montana	1,016,967	3,877,478
Nebraska	29,345	226,810
Nevada	77,180	5,847,070
New Hampshire	148	26,943
New Jersey	45,043	5,487,875
New Mexico	391,029	1,650,441
New York	24,345	16,035,410
North Carolina	60,116	19,392,624
North Dakota	72,205	541,217
Ohio	34,154	2,798,434
Oklahoma	10,175	1,310,523
Oregon	199,071	901,254
Pennsylvania	16,403	9,119,510
Rhode Island	5	50,668
South Carolina	32,583	1,406,724
South Dakota	273,618	3,733,160

Tennessee	11,416	7,678,481
Texas	1,236,404	5,372,427
Utah	855,390	8,046,646
Vermont	643	28,660
Virginia	253,492	22,930,227
Washington	1,964,392	7,091,427
West Virginia	88,006	1,641,563
Wisconsin	69,372	436,093
Wyoming	344,150	5,453,845

Source: Street, 2006.

Table 3-15. Additional National Park Service Aesthetic and Scenic Resources (2005)

States	Sites
Alaska to Washington	13,192 acres of the Klondike Gold Rush National Historical Park
Arizona and Utah	1,254,429 acres of Glen Canyon National Recreation Area
Arkansas and Oklahoma	75 acres of Fort Smith National Historical Site
California and Nevada	3,372,402 acres of the Death Valley National Park
Colorado and Utah	210,278 acres of Dinosaur National Monument
Colorado and Utah	785 acres of Hovenweep National Monument
Georgia and Tennessee	9,036 acres of the Chickamauga & Chattanooga National Military Park
Idaho, Montana, and Wyoming	2,219,791 acres of Yellowstone National Park
Kentucky and Tennessee	125,310 acres of Big South Fork National River and Recreation Area
Kentucky, Tennessee and Virginia	20,512 acres of Cumberland Gap National Historic Park
Maine to Georgia	226,498 acres of Appalachian National Scenic Trail
Maryland and Virginia	39,727 acres of the Assateague Island National Seashore
Maryland and Virginia	7,239 acres of the George Washington Memorial Parkway
Maryland, Virginia, and Washington, D.C.	6,693 acres of National Capitol Parks
Maryland, Virginia and West Virginia	3,646 acres of Harper's Ferry National Historical Park
Maryland, West Virginia and Washington, D.C.	19,586 acres of the C&O Canal National Historical Park
Minnesota and Wisconsin	92,748 acres of the Saint Croix National Seashore
Mississippi to Florida	137,990 acres of the Gulf Islands National Site
Mississippi to Tennessee	10,995 acres of Natchez Trace National Scenic Trail
Missouri and Illinois	91 acres of the Jefferson National Memorial which extends from Missouri to Illinois.
Montana and North Dakota	444 acres of the Fort Union Trading Post National Historical Site;
Montana and Wyoming	120,296 acres of Bighorn Canyon National Recreation Area
Nevada to Arizona	1,495,664 acres of the Lake Mead National Recreation Area
New Jersey and New York	26,607 acres of Gateway National Recreation Area
New Jersey and Pennsylvania	66,739 acres of Delaware Water Gap National Recreation Area
New Jersey and Pennsylvania	1,973 acres of Delaware National Scenic River
New York and New Jersey	61 acres of Statue of Liberty National Monument
New York and Pennsylvania	75,000 Upper Delaware Scenic and Recreational River
North Carolina and Virginia	93,735 acres of the Blue Ridge Parkway
South Dakota and Nebraska	34,159 acres of the Missouri River National Recreational River
Tennessee and Mississippi	51,824 acres of the Natchez Trace Parkway
Tennessee and North Carolina	522,199 acres of the Great Smoky Mountains National Park

Table 3-16. State Forests and Parks

State	State Forests		State Parks	
	Number	Acreage	Number	Acreage
Alabama	21	48,000	22	45,614
Alaska	NA	NA	>100	3,500,000
Arizona	NA	NA	28	NA
Arkansas	NA	NA	51	NA
California	NA	NA	278	1,500,000
Colorado	1	71,000	44	160,000
Connecticut	94	170,000	94	32,960
Delaware	3	>15,000	14	>20,000
Florida	31	>890,000	159	>723,000
Georgia	6	63,294	64	65,066
Hawaii	19	>109,000	52	25,000
Idaho	NA	881,000	30	>43,000
Illinois	NA	NA	NA	NA
Indiana	NA	NA	23	56,409
Iowa	10	43,917	84	53,000
Kansas	NA	NA	24	NA
Kentucky	5	35,809	52	NA
Louisiana	1	8,000	35	NA
Maine	1	21,000	>30	NA
Maryland	7	136,907	40	90,293
Massachusetts	NA	NA	NA	NA
Michigan	NA	NA	96	265,000
Minnesota	58	<4,000,000	72	NA
Mississippi	NA	NA	24	NA
Missouri	NA	NA	NA	NA
Montana	7	214,000	110	18,273
Nebraska	NA	NA	87	NA
Nevada	NA	NA	24	NA
New Hampshire	NA	NA	72	NA
New Jersey	11	NA	42	NA
New Mexico	NA	NA	31	NA
New York	2	2,750,000	176	NA
North Carolina	NA	NA	29	NA
North Dakota	NA	NA	17	NA
Ohio	20	>183,000	74	>204,000
Oklahoma	NA	NA	50	NA
Oregon	NA	780,000	231	95,462
Pennsylvania	NA	>2,000,000	116	NA
Rhode Island	NA	NA	14	NA
South Carolina	4	NA	47	>80,000

State	State Forests		State Parks	
	Number	Acreage	Number	Acreage
South Dakota	NA	NA	12	NA
Tennessee	15	162,371	54	NA
Texas	5	7,314	115	>600,000
Utah	NA	NA	NA	NA
Vermont	NA	300,000	52	NA
Virginia	16	750,000	34	NA
Washington	NA	2,100,000	120	NA
West Virginia	9	79,502	37	74,508
Wisconsin	NA	NA	NA	NA
Wyoming	NA	NA	NA	NA

NA = data not available
Source: Infoplease, 2006.

3.7.2.1 Unique Geographic Features and Scenic Resources

A brief list of unique geographic features and scenic resources by state is provided in Table 3-17.

Table 3-17. Unique Geographic Features and Scenic Resources

State	Unique Geographic Features and Scenic Resources
Alaska	Denali National Park, Mendenhall Glacier, and the Katmai National Park that includes the “Valley of Ten Thousand Smokes,” an area of active volcanoes;
Arizona	The Grand Canyon National Park is one of the most studied geologic landscapes in the world. The park encompasses 1,218,375 acres, lies on the Colorado Plateau in northwestern Arizona, contains several major ecosystems, and “offers an excellent record of three of the four eras of geological time, a rich and diverse fossil record, a vast array of geologic features and rock types, and numerous caves containing extensive and significant geological, paleontological, archeological and biological resources” (NPS, 2005c)
California	Yosemite National Park (California), “embraces a spectacular tract of mountain-and-valley scenery in the Sierra Nevada, which was set aside as a national park in 1890. The park harbors a grand collection of waterfalls, meadows, and forests that include groves of giant sequoias, the world's largest living things” (NPS, 2005d). Also Sequoia and Kings Canyon National Parks and Pacific Coast Highway.
Colorado	Breathtaking scenery and world-class skiing make Colorado a prime tourist destination; however, Revised Statute 2477 threatens scenic quality of these areas by allowing “the right of way for the construction of highways over public lands, not reserved for public uses” (State of Colorado, 2005). Colorado includes more than 1,000 Rocky Mountain peaks over 10,000 ft high and 54 towering peaks above 14,000 ft. Pike’s Peak is the most famous of these mountains.
Florida	Florida’s Everglades National Park, the Nation’s only subtropical preserve, which is formed by a freshwater river 6 inches deep and 50 miles wide
Gulf Coast States	Gulf Coast Resort areas
Hawaii	In the northwest interior of Kaua’i is Waimea Canyon, also known as the Grand Canyon of the Pacific, and the high altitude Alaka’i Swamp. In the center of Kaua’i is the top of the inactive Wai’ale’ale volcano. The summit gets an average of 1.5 inches of rain everyday, making it the wettest palce on earth.(Wikipedia, 2006).
Idaho	Idaho has numerous lakes, glaciers, and mountains, such as Craters of the Moon National Monument. Idaho's many streams and lakes provide fishing, camping, and boating sites. The nation's largest elk herds draw hunters from all over the world, and the famed Sun Valley resort attracts thousands of visitors to its swimming, golfing, and skiing facilities” (Infoplease, 2004).
Indiana	Wyandotte Cave located in Indiana, which is one of the largest in the U.S.
Kentucky	Mammoth Cave National Park featuring an extensive cave system.

State	Unique Geographic Features and Scenic Resources
Maryland	Maryland's Chesapeake Bay is one of the largest and most productive estuaries in the U.S. Over 200 miles long and fed by thousands of rivers and streams, the bay's watershed covers nearly 64,000 square miles.
Michigan	Michigan alone borders on four of the five Great Lakes and includes 3,288 miles of Great Lake shoreline.
Minnesota	Minnesota's key scenic resource is its more than 10,000 lakes and Great Lake shoreline.
Montana	Glacier National Park, on the Continental Divide, has 60 glaciers, 200 lakes, and many streams with good trout fishing" (Pearson Education, 2004).
Nevada/ Arizona	Hoover Dam (Nevada and Arizona), one of the largest dams in the world and a principal source of irrigation, flood control, and electrical power in the Southwest.
New Mexico	Carlsbad Caverns National Park.
New York	Niagara Falls is a set of massive waterfalls located on the Niagara River on the border between the U.S. and Canada (Wikipedia, 2006a).
North Carolina	The Great Smoky Mountains, the Blue Ridge National Parkway, and the Cape Hatteras and Cape Lookout National Seashores in North Carolina;
North Carolina/ Tennessee	Encompassing 800 square miles, the Great Smoky Mountains National Park in North Carolina and Tennessee is one of the largest protected areas in the Eastern U.S. With more than 9 million visitors annually, this park is threatened by acid deposition, O3 pollution, and mercury pollution.
Oregon	Crater Lake in south central Oregon, which includes a deep blue lake created by the eruption and collapse of Mt. Mazama almost 7,000 years ago
Pennsylvania	The "Grand Canyon of Pennsylvania" located in Tioga County and covering 300,000 acres.
South Dakota	Badlands National Park and Mount Rushmore (South Dakota)
Utah	Utah is a popular vacationland with 11,000 miles of fishing streams and 147,000 acres of lakes and reservoirs (Infoplease, 2004).
Virginia	Shenandoah National Park draws up to 2 million visitors per year. Air quality is an important aspect of maintaining the scenic quality of the area. Because the park is located downwind of a number of major industrial and urban areas, air pollution, particularly during the summer months, has significantly degraded the distance, color, contrast, and landscape details of park views from Skyline Drive. In addition, "foliar injury caused by ground-level ozone has impaired the aesthetics of many of the park's 40 known ozone-sensitive plant species." (NPS, 2005b)
Washington	Mount St. Helens (Washington), a peak in the Cascade Range, which experienced a major eruption in May 1980.
West Virginia	Blackwater Canyon located below Blackwater Falls State Park and surrounded by the Monongahela National Forest in West Virginia.
Wyoming	Yellowstone National Park, Grand Teton Range, and Devil's Tower.

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3.8 LAND USE

This section describes land uses that may be affected by carbon sequestration projects.

3.8.1 National Context

The U.S. has a total land area of approximately 2,263 million acres. Table 3-18 summarizes the major land uses for the entire country (Vesterby and Krupa, 2001). In this table and throughout the land use section, the following definitions apply:

- "Cropland" includes all land in crop production, plus idle cropland and croplands used only for pasture.
- "Grassland" includes permanent grassland, plus non-forested pasture and range.
- "Forest" includes lands classified as such by the U.S. Forest Service, excluding approximately 105 million acres in parks and other special uses.
- "Special use" land includes these 105 million acres, plus other lands used for national and state parks, wilderness and wildlife areas, Federal installations (mainly DOD and DOE), rural highways and roads, railroads, rural airports, and farmsteads.
- "Urban" land includes urbanized areas and jurisdictions with populations of 2,500 or more.
- "Other" land includes marshes, open swamps, desert, tundra, bare rock areas, and other uses not categorized.

Table 3-18. Major Land Uses (1997) in the United States (million acres)

Land Use	Entire United States (million acres)	Portion of Total
Cropland	455	20%
Grassland	580	26%
Forest	641	28%
Special Use	286	13%
Urban	66	3%
Other	235	10%
Total	2,263	

Source: Vesterby and Krupa, 2001.

Nearly half of the land area (46 percent) is cropland or grassland; forests account for an additional 28 percent of the total land area. Also, the special use category includes approximately 247 million acres of land used for national and state parks, wilderness and wildlife areas, and Federal installations, which represent an additional 11 percent of the total land. Furthermore, the other use category includes vegetated marshes and swamps. Therefore, at least 1,923 million acres (approximately 85 percent) of land supports substantial vegetation. This acreage provides a significant natural sink for terrestrial carbon sequestration with abundant opportunities for enhancement.

With respect to the distributions of major land uses throughout the 50 states, general patterns are indicated in Figure 3-27. Forested lands are significant in the southeastern, upper mid-western, and northwestern states, as well as in Alaska. Grasslands predominate in the plains and mountain states. Croplands are significant in mid-western, plains, and southeastern states. The west coast states, except Alaska, have significant acreage in all three categories.

Since 1959, the most significant trend in major land use on a nationwide basis has been the increase in special-use areas (132 percent), generally as a result of wilderness and wildlife area designations. Also, grassland has decreased by 8 percent since 1959, and cropland has declined by about 3 percent since 1978. More recently, in the years between 1992 and 1997, grassland decreased by 2 percent, while cropland and forests decreased by 1 percent each. During the same 5-year interval, special use lands increased by 2 percent and urban lands increased by nearly 11 percent. It can reasonably be assumed that these recent trends have continued to the present.

Urban lands nationwide comprised 66 million acres in 1997, representing approximately 3 percent of the total land area. Since 1960, urban land acreage nationwide increased by approximately 157 percent. The highest concentrations of urban lands are situated in the northeastern, upper mid-western, southeastern, and west coast states. Urban centers having the highest population density are illustrated in Figure 3-28.

The abundance of unmineable coal seams, deep-saline water-bearing formations, and depleted oil reserves in regions throughout the 48 conterminous states is important for geologic sequestration. These resources are described in more detail in Section 3.3, Geologic Resources.

The U.S. has approximately 12,383 statute miles of seacoast based on the general outline of seacoast measured in 30 minutes of latitude on charts as near a scale of 1:1,200,000 as possible (Pearson Education, 2004). The proximity to the ocean is of significance for potential future ocean sequestration projects.

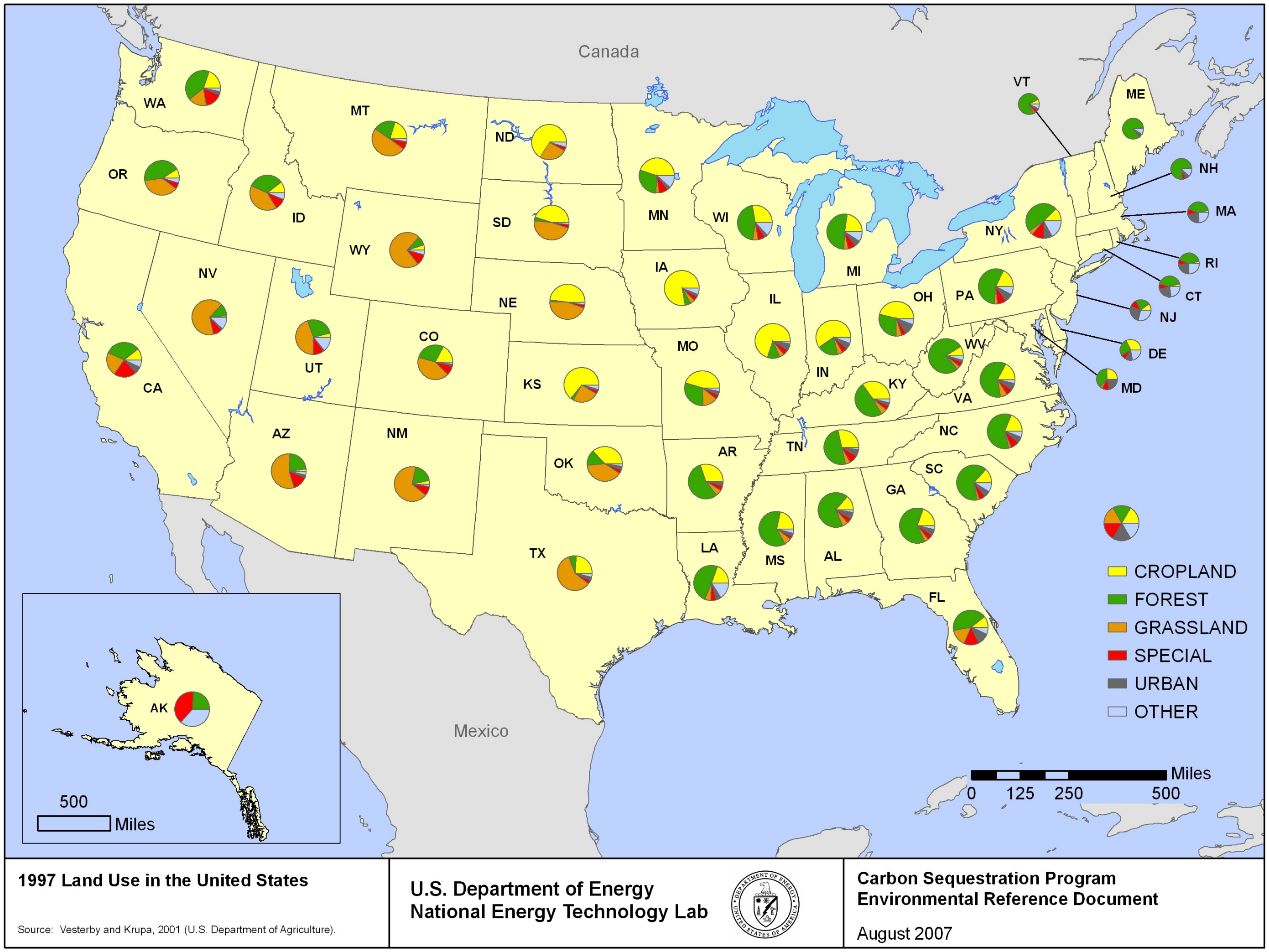

Figure 3-27. Land Use

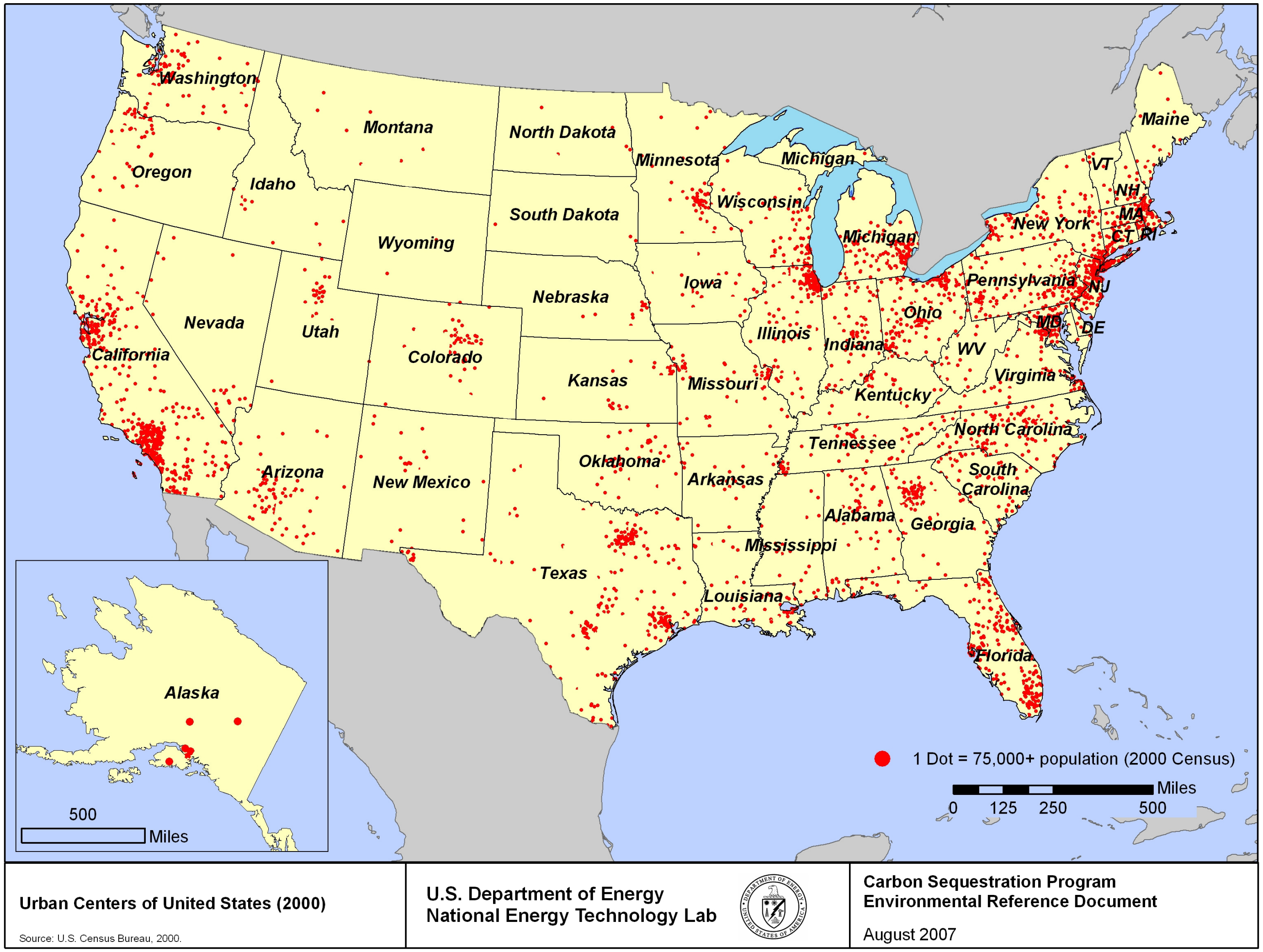

Figure 3-28. Population

3.8.2 State Land Uses

Land uses by state are shown in Table 3-19.

Table 3-19. Major Land Uses (1997) by State

State	Cropland	Grassland	Forest	Special Use	Urban	Other	Total
	in 1,000 Acres						
Alabama	4,471	1,860	21,911	1,423	2,000	815	32,480
Alaska	68	1,226	87,936	143,013	567	132,229	365,039
Arizona	1,254	40,509	16,306	10,092	1,746	2,825	72,732
Arkansas	10,082	2,006	18,392	1,450	931	467	33,328
California	10,628	22,343	32,579	20,996	5,922	7,355	99,823
Colorado	11,415	27,867	18,781	5,699	1,070	1,553	66,385
Connecticut	166	30	1,682	299	910	923	4,011
Delaware	451	8	376	102	154	313	1,405
District of Columbia	0	0	0	0	39	39	78
Florida	3,650	5,455	14,605	4,676	3,902	2,270	34,558
Georgia	7,329	1,336	23,004	1,854	2,132	1,412	37,068
Hawaii	293	961	1,189	769	678	898	4,789
Idaho	5,766	21,165	17,123	5,266	233	3,408	52,961
Illinois	24,925	1,559	4,058	1,901	2,215	922	35,580
Indiana	13,689	1,158	4,342	1,102	1,325	1,341	22,957
Iowa	27,911	1,477	1,944	1,550	801	2,077	35,760
Kansas	33,708	12,560	1,492	1,620	693	2,294	52,367
Kentucky	8,860	1,491	12,348	996	793	940	25,429
Louisiana	5,485	1,582	13,691	1,395	1,282	4,447	27,882
Maine	466	37	16,952	520	581	1,778	20,334
Maryland	1,555	208	2,424	731	1,208	130	6,256
Massachusetts	211	35	2,675	553	1,515	1,542	6,531
Michigan	8,304	1,606	18,667	2,468	1,896	3,417	36,358
Minnesota	22,839	1,544	14,820	4,398	1,419	5,934	50,954
Mississippi	6,464	1,946	18,589	848	852	1,327	30,025
Missouri	20,013	6,010	13,411	1,740	1,390	1,531	44,095
Montana	18,573	46,039	19,165	6,414	196	2,769	93,156
Nebraska	23,555	21,828	797	1,423	294	1,305	49,202
Nevada	867	46,278	8,199	5,726	801	8,403	70,274
New Hampshire	112	40	4,551	317	376	720	6,116
New Jersey	634	29	1,507	728	1,712	1,850	6,460
New Mexico	2,427	52,188	14,084	6,360	636	1,979	77,674
New York	4,112	1,314	15,405	3,810	2,431	5,581	32,654
North Carolina	5,890	814	18,638	2,264	1,760	1,814	31,180
North Dakota	28,818	11,329	441	1,489	129	1,950	44,156
Ohio	12,026	1,376	7,567	1,153	2,559	1,528	26,209
Oklahoma	16,336	17,314	6,233	1,477	1,473	1,120	43,953

State	Cropland	Grassland	Forest	Special Use	Urban	Other	Total
	in 1,000 Acres						
Oregon	5,338	22,395	26,664	3,593	610	2,840	61,440
Pennsylvania	5,181	910	15,852	2,379	2,146	2,218	28,685
Rhode Island	30	3	356	61	214	220	883
South Carolina	2,532	465	12,418	1,032	1,102	1,722	19,271
South Dakota	21,765	22,594	1,588	1,575	150	901	48,573
Tennessee	7,491	1,123	13,265	2,203	1,695	603	26,380
Texas	40,040	98,059	11,767	5,363	5,697	6,699	167,625
Utah	2,045	23,737	13,832	5,058	549	7,367	52,588
Vermont	484	212	4,462	337	120	425	6,040
Virginia	4,340	1,533	15,345	1,468	1,654	1,003	25,343
Washington	8,400	7,406	17,418	6,639	1,371	1,378	42,612
West Virginia	1,411	481	11,899	699	288	637	15,415
Wisconsin	9,561	1,844	15,701	2,182	1,113	4,359	34,760
Wyoming	3,080	44,873	5,085	6,332	206	2,571	62,147

Source: Vesterby and Krupa, 2001.
(See land use definitions in Section 3.8.1)

3.9 MATERIALS AND WASTE MANAGEMENT

A range of chemical materials would be expected to be used in carbon sequestration projects. The sequestration technologies would also produce certain solid and hazardous wastes. This section describes the types of materials and wastes that are anticipated to be part of the projects.

3.9.1 Materials

The major types of chemical materials that would be used in processes that would be part of the potential geologic sequestration project include: fuels, tracers, and process chemicals as illustrated in Table 3-20. The table also lists the model projects and the various types of materials that may be used.

Fuels that are most likely to be used for project processes are electricity, diesel fuel, natural gas, and propane. The selection of the specific fuel type depends upon the location of the project and availability of fuels (some facilities may not be close enough to existing power lines to use that service) and the purpose of the fuel (operate electrical equipment or heat a process stream).

Process chemicals can include chemicals used for chiller operation, catalysts or reagents to facilitate the separation of gases in a process stream, and compounds to assist in process stream phase change. Amine and soda ash are process chemicals that would be expected to be used in post combustion capture projects. Anhydrous ammonia is a process chemical commonly used to operate a commercial size chiller for compression of gases. Amine is a process chemical that would be used for some projects. Amine (Diethanolamine or DEA) is corrosive and toxic. As such, care would be taken to handle and store the materials properly to avoid spills, leaks or misuse. The Material Safety Data Sheet (MSDS) for DEA (Mallinkrodt Baker, 2005) lists the chemical as having a moderate health rating (2), Slight flammability rating, Moderate Reactivity Rating and as Severe rating for contact.

Table 3-20. Project Materials for Selected Carbon Sequestration Projects.

Model Project	Material Type	Purpose	Example Material
Post Combustion Capture	Fuel	Electric operated equipment	Line power from collocated power plant
	Fuel	Standby generator	Diesel fuel
	Solvent	Process chemical used in the capture of CO_2	Amine
	Caustic	Process chemical used in the capture of CO_2	Soda Ash
CO_2 Compression and Transportation	Fuel	Electric operated equipment	Line power or diesel generator
	Fuel	Standby generator	Diesel fuel
	Chiller Process Chemicals	Compressor operation	Anhydrous ammonia
Coal Seam Sequestration	Fuel	Heater operation	Natural Gas or diesel fuel
	Fuel	Electric operated equipment	Line power or diesel generator
	Fuel	Standby generator	Diesel fuel
	Tracer	Used to determine the fate and transport of the injected CO_2 stream	See Table 3-21
Saline Formation Injection	Fuel	Electric operated equipment	Line power or diesel generator
	Standby generator	Electric operated equipment	Diesel fuel
	Tracer	Used to determine the fate and transport of the injected CO_2 stream	See Table 3-21
Enhanced Oil Recovery	Fuel	Electric operated equipment	Line power or diesel generator

Model Project	Material Type	Purpose	Example Material
	Fuel	Standby generator	Diesel fuel
	Tracer	Used to determine the fate and transport of the injected CO_2 stream	See Table 3-21
Terrestrial Sequestration - Reforestation	Fuel	Machinery such as tractors, disks, and rangeland seeders.	Diesel fuel
	Herbicide	Control of weeds or other invasive plant species that could preclude the success of reforestation	To be determined
	Pesticide	Control of insect populations that could threaten the success of reforestation.	To be determined
Co-Sequestration	Fuel	Electric operated equipment	Line power or diesel generator
		Standby generator	Diesel fuel
	Solvent	Process chemical used in the capture of CO_2	Amine

Tracers are used in field validation projects to help the researchers learn about the behavior of the CO_2 stream that is injected into a formation. The chemicals are selected because:

- they can be easily measured at monitoring wells
- they are not commonly found in nature
- they do not rapidly degrade or interact with compounds in the formation or the injectate
- they display low toxicity to biota.

Examples of tracers that have been proposed for use in carbon sequestration field tests are listed in Table 3-21 from the Draft Environmental Assessment for Pilot Experiment for Geological Sequestration of CO_2 in Saline Aquifer Brine Formations (DOE, 2003). This experiment was begun in the fall of 2004 in Frio County, Texas.

A variety of construction materials would be used in the construction activities including: concrete, structural steel, plastics, composites, sheetrock, paint, floor coverings, and other items. These are common items used in new industrial construction that would not require special production capability for these materials to be obtained. Leftover materials will be properly disposed or reused as appropriate.

3.9.2 Waste Management

Several types of waste are typically associated with carbon sequestration projects as listed in Table 3-22. These wastes would not exist prior to implementation of the projects. However, if a carbon sequestration project is collocated with another type of energy project (i.e., coal-fired power plant or oil and gas field), a range of wastes would already be generated and managed for the other energy projects. Where existing projects are already in place, a system of waste management could potentially be utilized by the carbon sequestration project.

The quantities of wastes and properties of those wastes would be determined during the project development phase. NEPA studies for future projects should evaluate the extent of existing waste management facilities including permitted landfill operations. They should also address the extent and capabilities of local waste management services to accommodate wastes that would be newly generated by the proposed project.

Table 3-21. Tracers Proposed for Use in Saline CO_2 Injection Pilot Experiment

Tracer	Concentration (Injectate)	Concentration Produced Fluids	Maximum Total Weight	Comments
FLUTEC-TG PMCH (perfluoromethylcyclohexane)	30 µg/mL (30 ppm)	1 ng/mL (1 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG PTMCH (perfluoro-1,3,5-trimethyleyeclohexane)	30 µg/mL (30 ppm)	1 ng/mL (1 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG o-PDMCH (perfluoro-1,2-dimethyleclohexane)	30 µg/mL (30 ppm)	1 ng/mL (1 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG m-PDMCH (perfluoro-1,3-dimethylcyclohexane)	7 µg/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG p-PDMCH (perfluoro-1,4-dimethylcyclohexane)	7 µg/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG PMCH (perfluorodimethylcyclopentane)	30 µg/mL (30 ppm)	1 ng/mL (1 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG PDMCB (perfluorodimethylcyclobutane)	7 µg/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
FLUTEC-TG PECH (perfluorodimethylcyclohexane)	7 µg/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Perfluoro-carbons: 60 kg total	No known human- or eco-toxicity
^{20}Ne (Neon 20)	30.3 ppm	Variable	0.63 kg	No known human- or eco-toxicity
^{36}Ar (Argon 36)	164 ppm	Variable	3.42 kg	No known human- or eco-toxicity
^{84}Kr (Krypton 84)	7.64 ppm	Variable	0.16 kg	No known human- or eco-toxicity
^{132}Xe (Xenon 132)	0.4 ppm	Variable	0.01 kg	No known human- or eco-toxicity
Eosin	1 ppm	5 ppb	10 kg	No known human- or eco-toxicity

Source: DOE, 2003.

Table 3-22. Waste Types

Model Project	Waste Type	Typical Disposal
Post Combustion Capture	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
CO_2 Compression and Transportation	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
Coal Seam Sequestration	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
	Drill cuttings	Onsite or local landfill
	Circulation mud pit	Onsite or local landfill
	Produced water	Depends on local conditions

Model Project	Waste Type	Typical Disposal
Saline Formation Injection	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
	Drill cuttings	Onsite or local landfill
	Circulation mud pit	Onsite or local landfill
	Produced water	Depends on local conditions
Enhanced Oil Recovery	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
	Drill cuttings	Onsite or local landfill
	Circulation mud pit	Onsite or local landfill
	Produced water	Depends on local conditions
Terrestrial Sequestration - Reforestation	Wastewater	Onsite treatment or discharge to a permitted treatment works
	Municipal waste	Local permitted municipal landfill
	Unused herbicides and pesticides	Permitted treatment, storage and disposal facility
	Green waste from land clearing	Compost facility

3.10 HUMAN HEALTH EFFECTS AND SAFETY

This section describes the context for consideration of human health effects and safety that would be created by future carbon sequestration projects. Two aspects of worker health and safety impacts are discussed: worker injuries and worker fatalities that are associated with the construction or operation of carbon sequestration projects.

Public health and safety related to carbon sequestration projects can be measured on the basis of many factors. For this document the existing environment is assumed to consist of an existing industrial facility in almost every case, except for terrestrial sequestration. Many industrial facilities use hazardous or toxic materials in the processes. Under normal conditions these materials can be used safely assuming proper safety precautions are followed. Using highly toxic materials poses additional risk of accidental releases of toxic air emissions that pose a risk to the public in the surrounding area. The EPA issued rules to implement provisions of the Clean Air Act Amendments of 1990 that requires the owner of a facility that uses extremely toxic materials to prepare a Risk Management Plan (RMP). If an existing facility does not require an RMP it is assumed to pose a smaller risk of accidental release of toxic materials to the air than a facility that does require an RMP. The following sections explain the concept in more detail.

3.10.1 National Context

In general, most of the Carbon Sequestration projects analyzed in this document are not stand-alone projects. For example, a Post-Combustion Capture Project would be collocated with an existing coal-fired power plant. Therefore, health and safety aspects of sequestration components or technologies may be similar to their partner site or industry. A listing of a representative "existing facilities" is presented to use as a backdrop for comparison of environmental impacts that will be discussed in Chapter 4. Table 3-23 lists potential carbon sequestration projects and representative existing facilities.

Table 3-23. Carbon Sequestration Projects and Anticipated Co-Located Facilities

Project	Primary Existing Facility	Industry Category	Industry Code (NAICS Code (1))	Incidence rates(2) of nonfatal occupational injuries and illnesses	Occupational fatalities in 2003	Risk Management Plan Required for use of Extremely Hazardous Materials (Compounds that trigger preparation of an RMP)
Post Combustion Capture	Coal-Fired Power Plant	Utilities-Electric Power Generation	221110	3.5	8	No
CO_2 Compression and Transportation	Coal-Fired Power Plant	Utilities-Electric Power Generation	221110	3.5	8	No
		Pipeline Transportation of Natural Gas	486200	2.4	3	Yes Natural Gas Liquids (NGLs) in a CO_2 separation facility
Coal Seam Sequestration	Existing Coal Bed Methane recovery	Crude petroleum and natural gas	211111	1.7	16	Depends on the specific configuration
		Drilling Oil and Gas Wells	213111	4.0	26	
Saline Formation Injection	None	NA	NA	NA	NA	Depends on the specific configuration
		Drilling Oil and Gas Wells	213111	4.0	26	

Project	Primary Existing Facility	Industry Category	Industry Code (NAICS Code (1))	Incidence rates(2) of nonfatal occupational injuries and illnesses	Occupational fatalities in 2003	Risk Management Plan Required for use of Extremely Hazardous Materials (Compounds that trigger preparation of an RMP)
Enhanced Oil Recovery	Oil Well Field	Crude petroleum and natural gas	211111	1.7	16	Depends on the specific configuration
		Drilling Oil and Gas Wells	213111	4.0	26	
Terrestrial Sequestration-Reforestation	None	NA	NA	NA	NA	NA
Co-Sequestration of H_2S and CO_2 (from sour gas fields)	Oil or Gas Well Field	Crude Petroleum and natural gas	221110	3.5	8	No
		Drilling Oil and Gas Wells	213111	4.0	26	
Co-Sequestration of H_2S and CO_2 (from IGCC Plants)	Integrated Gasification Combined Cycle Plant	Utilities-Electric Power Generation	221110	3.5	8	No
		Drilling Oil and Gas Wells	213111	4.0	26	
U.S. Average – Private Industry				2.8		

1. North American Industry Classification System

2. The accident incidence rates represent the number of injuries and illnesses per 100 full-time workers and were calculated as: (N/EH) x 200,000, where

N = number of injuries and illnesses, EH = total hours worked by all employees during the calendar year

200,000= base for 100 equivalent full-time workers (working 40 hours per week, 50 weeks per year)

Source: U.S. Bureau of Labor Statistics, 2005 and U.S. Bureau of Labor Statistics, 2005a.

The types of health risks posed to workers by the assumed existing projects are generally those that are common to the industries that they represent. It is assumed that personnel protective equipment is used by workers at those facilities commensurate with the types of hazards that are present. For example, workers who work near equipment that generate dust would wear a respirator or dust mask as appropriate. The projects are also assumed to comply with applicable guidance of the Occupational Health and Safety Administration (Occupational Safety and Health Standards 29 CFR 1910).

3.10.2 Safety Data for Each State

This section describes the occupational injury rates and occupational fatality data for the 50 states. Occupational injury rates for private industry (2003) and numbers of occupational fatalities (2004) are summarized in Table 3-24.

Table 3-24. Occupational Injury and Fatality Rates by State

State	Occupational Injury Rate (2003)[1]	Occupational Fatalities by State (2004)[2]
Alabama	4.6	133
Alaska	7.0	42
Arizona	4.6	84
Arkansas	5.1	70
California	5.4	467
Colorado	NA	117
Connecticut	5.1	54
Delaware	4.3	10
District of Columbia	NA	11
Florida	5.0	422
Georgia	4.3	232
Hawaii	5.4	25
Idaho	NA	38
Illinois	4.6	208
Indiana	6.2	153
Iowa	6.7	82
Kansas	5.5	80
Kentucky	6.4	143
Louisiana	3.6	121
Maine	7.7	16
Maryland	4.1	81
Massachusetts	NA	72
Michigan	6.3	127
Minnesota	5.5	80
Mississippi	NA	88
Missouri	5.0	165
Montana	7.6	39
Nebraska	5.9	46
Nevada	5.7	61
New Hampshire	NA	15
New Jersey	4.2	129
New Mexico	6.1	57
New York	3.1	254
North Carolina	4.0	183
North Dakota	NA	24
Ohio	NA	202
Oklahoma	5.0	91
Oregon	5.6	60
Pennsylvania	NA	230
Rhode Island	5.4	7
South Carolina	4.4	113
South Dakota	NA	24
Tennessee	5.4	145
Texas	4.0	440
Utah	5.6	50
Vermont	5.2	7
Virginia	4.0	171

State	Occupational Injury Rate (2003)[1]	Occupational Fatalities by State (2004)[2]
Washington	6.8	98
West Virginia	6.1	58
Wisconsin	6.5	94
Wyoming	6.0	43

NA = data not available
Source: [1]U.S. Bureau of Labor Statistics, 2005; [2]U.S. Bureau of Labor Statistics, 2005b.

3.10.3 Other Health and Safety Considerations

The main health and safety risk in the direct use of CO_2 can result in large releases or releases in confined areas that can displace oxygen content in the air. This oxygen displacement can result in oxygen deprivation or death by suffocation. This is a significant safety risk in any operation where compressed CO_2 is used in very large quantities. If accidentally released into a confined space, such as an unventilated room or a large tank, CO_2 presents an odorless and invisible hazard to unsuspecting workers. Release of CO_2 to the atmosphere from geologic features is a process that occurs in nature. Large naturally occurring CO_2 releases are uncommon and have produced variable consequences. Two cases are noteworthy, Lake Nyos in Western Africa and Mammoth Mountain in California. Both Lake Nyos and Mammoth Mountain are atop current or former volcanoes and the release of CO_2 is volcanic in origin (DOE 2005a).

3.10.3.1 Lake Nyos CO_2 Release

Located in the west-African country of Cameroon, Lake Nyos is a few square kilometers in area and 200 meters (m) deep. It is situated in the crater formed from the collapse of the rock channel feeding a now extinct volcano. The lake is compositionally stratified, with fresh water in the upper 50 m and heavier sodium and carbon dioxide rich water below that. The water below 180 m is particularly rich in sodium and carbon dioxide. Most of the sodium and carbon dioxide come from numerous sodium-bicarbonate bearing springs - derived from an underlying magma chamber - feeding into the bottom of the lake.

In August of 1986 some event – perhaps a mudslide, heavy rain or wind blowing across the lake – caused the water column to be disturbed. Some of the deep carbon dioxide rich water moved towards the surface where it was subjected to lower pressure. The dissolved carbon dioxide quickly converted to carbon dioxide gas and rushed to the surface starting a chain reaction of degassing the deeper water. A huge cloud of carbon dioxide spilled over the lake's outlet and down into the surrounding valleys. Thousands of animals and 1700 people died, many in their sleep.

The lake is now degassed in a controlled way to prevent a reoccurrence. The procedure involves lowering a strong polyethylene pipe to the lake bottom. Some water is pumped out at the top, and as the deep water rises through the pipe the carbon dioxide starts to bubble out. The gas and water then become buoyant and suck more water in at the bottom in a self-sustaining process (DOE, 2005).

3.10.3.2 Mammoth Mountain CO_2 Release

Numerous small earthquakes occurred beneath Mammoth Mountain in California between May and November of 1989. Data collected from monitoring instruments during those months indicated that a small body of magma was rising through a fissure beneath the mountain. In the following year, U.S. Forest Service rangers noticed areas of dead and dying trees on the mountain. After drought and insect infestations were eliminated as causes, USGS scientists discovered that the roots of the trees were being killed by exceptionally high concentrations of CO_2 gas in the soil. Although trees produce oxygen (O_2)

from CO_2 during photosynthesis, their roots need to absorb O_2 directly. High CO_2 concentrations in the soil kill plants by denying their roots O_2 and by interfering with nutrient uptake. In the areas of tree kill at Mammoth Mountain, CO_2 makes up about 20 to 95 percent of the gas content of the soil; there is less than 1 percent CO_2 in soils outside the tree-kill areas. Today areas of dead and dying trees at Mammoth Mountain total more than 170 acres, with a total CO_2 flux of roughly 300 tons per day.

It is important to note that neither of the CO_2 release examples are from engineered CO_2 storage facilities. However, the consequences of the large, rapid releases of CO_2 can be dramatic and devastating to humans and the environment (DOE, 2005).

Carbon sequestration projects (other than terrestrial) tend to include large industrial facilities that can include machinery or other components that can pose health and safety risks to workers and the public should one of the processes malfunction. Under normal operating conditions the health and safety risks would be minimal. Malfunctions of project components, such as gas compressor units and liquid ammonia tanks for chillers, or the unsafe storage and handling of chemicals used in various gas treatment processes can pose health and safety hazards. Facilities must review health and safety regulations to determine if they are subject to preparation of a RMP. Certain oil and gas processing plants must prepare RMPs due to their use of large quantities of extremely toxic materials in the facility. An RMP is a requirement of the Chemical Accident Prevention Rule under the CAA Amendments of 1990 [42 U.S.C. s/s 7401 et seq., (1990)]. Whether or not a facility must prepare an RMP is determined by the amounts of materials used at the facility that are listed in the “List of Regulated Substances and Thresholds for Accidental Release Prevention” (40 CFR 9 and 68). Currently there are about 70 facilities in the U.S. that have RMPs where CO_2 is a major process stream. Some of these facilities are compressor stations for CO_2 pipelines that carry CO_2 to enhanced oil recovery operations. Other facilities include gas processing plants that separate various gas or liquid components that occur in a natural gas stream from a well head.

Co-locating a carbon sequestration facility with an existing facility may present a somewhat higher level of health and safety risk than if the two facilities were located separate from each other. This is due to the possibility that the risks of the two facilities together could be greater than the sum of two separate accident or release scenarios. An example is a fire and explosion at one facility that could be large enough to create a secondary explosion at the collocated facility. The EPCRA rules direct that an Offsite Consequence Analysis be performed if certain facility hazard conditions are present to help assist emergency responders in preparing for a potential emergency situation at the facility.

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3.11 SOCIOECONOMICS

This section describes socioeconomic conditions that may be affected by carbon sequestration projects.

As summarized in Table 3-25, the total population of the U.S. is approximately 294 million persons, of which minorities comprise approximately 31 percent. In the 2000 decennial census, 12.4 percent of individuals had incomes below the poverty level. The national population in 2000 had a median age of 35.3 years and an average family size of 3.14 persons.

The national population grew by slightly more than 13 percent in the ten years between 1990 and 2000, while the minority population increased by 43 percent. In the 1990 decennial census, 13.1 percent of individuals had incomes below the poverty level, but the number of individuals in poverty increased by 6.8 percent from 1989 to 1999. The median age of the population in 1990 was 32.9 years and the average family size was 3.16 persons. These comparisons indicate that the proportion of minorities in the U.S. is increasing, the general population is aging, families are becoming smaller, and the poverty rate is declining, but the number of individuals in poverty is increasing.

Table 3-25. Demographics of the U.S.

Jurisdiction	Population	Growth Rate (1990-2000)	Percent Minorities	Individual Poverty Rate	Median Age	Average Family Size
United States	293,655,404	13.2%	30.7%	12.4%	35.3	3.14

Note: Population estimate for mid-2004; all other data from 2000 census.
Minorities include Black or African American, American Indian or Alaska Native, Asian, Native Hawaiian or Pacific Islander, and Hispanic or Latino, as well as two or more races; excluded are White alone or Some Other Race alone.

Source: U.S. Census Bureau, 2005.

Table 3-26 summarizes housing characteristics in the U.S. The nation added a total of 13.6 million housing units from 1990 to 2000, yielding a rate of increase (13.3 percent) that matched population growth. However, the proportion of new housing units constructed over the same decade ran a few percentage points higher, which indicates that a substantial decrease in older housing stock occurred. The occupancy rate increased from 90 to 91 percent during the decade, and the proportion of rural housing declined from 25.5 to 22.4 percent. During the 1990s, the median unit value of owner-occupied housing increased by more than 52 percent, while the median gross rent increased by nearly 35 percent.

Table 3-26. Housing Characteristics of the U.S.

Jurisdiction	Total Housing Units	Occupancy Rate	Percent Built since 1990	Percent Rural Housing	Median Unit Value	Median Gross Rent
United States	115,904,641	91.0%	17.0%	22.4%	$119,600	$602

Note: All data from 2000 census

Source: U.S. Census Bureau, 2005.

Table 3-27 summarizes economic characteristics of the U.S. The gross domestic product (GDP) of the nation grew by 4.8 percent in 2003, while in the ten years between 1992 and 2002 the GDP grew by an average annual rate of 6.9 percent. The GDP per capita grew by an average annual rate of 4.6 percent during the same ten-year span, while per capita income increased by an average annual rate of 5 percent between the last two decennial censuses. The unemployment rate at the end of 2004 was 5.4 percent. Over the past 20 years, the average annual unemployment rate in the U.S. has ranged between 4.0 and 7.5 percent.

Table 3-27. Economic Characteristics of the U.S.

Jurisdiction	Gross Domestic Product ($B)	Percent Change 2002-03	GDP Per Capita	Revenue Per Capita	Revenue: Expenditure Ratio	Income Per Capita	Unemploy -ment Rate	Res. Elec. Bill (Avg. mo.)
United States	$10,911	4.8%	$37,520	$3,820	0.86	$21,587	5.4%	$76.74

Note: Gross product data for 2003; revenue data for 2002; income per capita for 1999; unemployment rate for December 2004; avg. monthly electric bill for 2002.

Source: U.S. Census Bureau, 2005 and 2004; U.S. BEA, 2005; U.S. BLS, 2005; EIA, 2002.

The average monthly electric bills in 2002 were $76.74 for residential customers, $478.41 for commercial customers and $6,647.01 for industrial customers. Average revenues per Kilowatt hour were 8.46, 7.86, and 4.88 cents, respectively, for residential, commercial, and industrial customers (EIA, 2002).

Information concerning demographics, housing characteristics, and economic characteristics for each state is provided in Table 3-28 through Table 3-30.

Table 3-28. Demographics of the States

Jurisdiction	Population	Growth Rate (1990-2000)	Percent Minorities	Individual Poverty Rate	Median Age	Average Household Size
Alabama	4,447,100	10.1	29.0	17	37.4	2.49
Alaska	626,932	14.0	30.8	11.2	33.9	2.74
Arizona	5,130,632	40.0	23.8	14.2	34.5	2.64
Arkansas	2,673,400	13.7	21.0	17.2	37.0	2.49
California	33,871,648	13.8	39.1	13.3	34.4	2.87
Colorado	4,301,261	30.6	16.5	11.1	34.7	2.53
Connecticut	3,405,565	3.6	18.8	8.3	39.3	2.53
Delaware	783,600	17.6	26.4	10.4	37.9	2.54
District of Columbia	572,059	-5.7	67.6	19	35.9	2.16
Florida	15,982,378	23.5	23.2	12.8	39.5	2.46
Georgia	8,186,453	26.4	37.5	14.4	34.3	2.65
Hawaii	1,211,537	9.3	75.7	9.8	38.5	2.92
Idaho	1,293,953	28.5	8.2	13.9	34.6	2.69
Illinois	12,419,293	8.6	27.8	12	35.6	2.63
Indiana	6,080,485	9.7	13.9	12.2	36.1	2.53
Iowa	2,926,324	5.4	6.5	10.9	38.6	2.46
Kansas	2,688,418	8.5	14.8	11.7	36.1	2.51
Kentucky	4,041,769	9.7	10.1	16.8	37.5	2.47
Louisiana	4,4468,976	5.9	36.3	19.8	35.4	2.62
Maine	1,274,923	3.8	3.4	12.6	41.2	2.39
Maryland	5,296,486	10.8	38.5	8.2	37.1	2.61
Massachusetts	6,349,097	5.5	16.6	10.3	38.2	2.51
Michigan	9,938,440	6.9	20.0	13.2	36.9	2.56
Minnesota	4,919,479	12.4	12.0	9.2	36.7	2.52
Mississippi	2,844,658	10.5	39.2	21.3	35.5	2.63

Jurisdiction	Population	Growth Rate (1990-2000)	Percent Minorities	Individual Poverty Rate	Median Age	Average Household Size
Missouri	5,595,211	9.3	15.5	13.3	37.4	2.48
Montana	902,195	12.9	9.4	14.4	40.2	2.45
Nebraska	1,711,263	8.4	10.4	10.9	36.2	2.49
Nevada	1,998,257	66.3	23.9	11.1	35.2	2.62
New Hampshire	1,235,786	11.4	4.5	7.5	39.5	2.53
New Jersey	8,414,350	8.9	30.1	8.7	38	2.68
New Mexico	1,819,046	20.1	30.5	18.5	36.2	2.63
New York	18,976,457	5.5	32.9	13.8	37.5	2.61
North Carolina	8,049,313	21.4	28.6	15.1	36.2	2.49
North Dakota	642,200	0.5	8.5	11.2	39.1	2.41
Ohio	11,353,140	4.7	15.7	13	37.6	2.49
Oklahoma	3,450,654	9.7	24.6	16.5	36.5	2.49
Oregon	3,421,399	20.4	13.2	14.1	37	2.51
Pennsylvania	12,281,054	3.4	15.4	11.9	39.7	2.48
Rhode Island	1,048,319	4.5	17.1	12.3	38.4	2.47
South Carolina	4,012,012	15.1	32.6	15.6	37.1	2.53
South Dakota	754,844	8.5	12.0	13.6	37	2.50
Tennessee	5,689,283	16.7	20.4	15.5	37.3	2.48
Texas	20,851,820	22.8	28.1	17.6	33.2	2.74
Utah	2,233,169	29.6	10.2	10.2	28.5	3.13
Vermont	608,827	8.2	3.4	11.5	40.7	2.44
Virginia	7,078,515	14.4	28.3	10	37.2	2.54
Washington	5,894,121	21.1	18.8	11.9	36.7	2.53
West Virginia	1,808,344	0.8	5.0	18	40.7	2.40
Wisconsin	5,363,675	9.6	11.9	10.2	37.9	2.50
Wyoming	493,782	8.9	7.6	9.5	39.1	2.48

Note: All data from 2000 census

Source: U.S. Census Bureau, 2005.

Table 3-29. Housing Characteristics of the States

Jurisdiction	Total Housing Units	Occupancy Rate (%)	Percent Built since 1990	Percent Rural Housing	Median Housing Value ($)	Median Gross Rent ($)
Alabama	1,963,711	88.5	22.6	44.6	97,500	535
Alaska	260,978	84.9	18.0	34.3	197,100	832
Arizona	2,189,189	86.8	29.3	11.8	185,400	717
Arkansas	1,173,043	88.9	22.1	47.6	87,400	549
California	12,214,549	94.2	12.9	5.5	477,700	973
Colorado	1,808,037	91.7	22.1	15.5	223,300	757
Connecticut	1,385,975	93.9	8.6	12.3	271,500	839
Delaware	343,072	87.0	21.2	19.9	203,800	793
District of Columbia	274,845	90.4	2.6	0.0	384,400	832
Florida	7,302,947	86.8	22.7	10.7	189,500	809
Georgia	3,281,737	91.6	27.9	28.3	147,500	709
Hawaii	460,542	87.6	18.1	8.5	272,700	779
Idaho	527,824	89.0	25.4	33.7	134,900	594
Illinois	4,885,615	94.0	12.4	12.1	183,900	734
Indiana	2,532,319	92.3	17.3	29.2	114,400	615
Iowa	1,232,511	93.2	12.3	38.9	106,600	559
Kansas	1,131,200	91.8	14.6	28.6	107,800	588
Kentucky	1,750,927	90.8	21.2	44.3	103,900	527
Louisiana	1,847,181	89.6	14.6	27.3	101,700	569
Maine	651,901	79.5	14.6	59.8	155,300	623
Maryland	2,145,283	92.3	16.7	13.9	280,200	891
Massachusetts	2,621,989	93.2	8.3	8.6	361,500	902
Michigan	4,234,279	89.4	14.7	25.4	149,300	655
Minnesota	2,065,946	91.7	16.1	29.1	198,800	692
Mississippi	1,161,953	90.0	22.1	51.2	82,700	538
Missouri	2,442,017	89.9	17.0	30.6	123,100	593
Montana	412,633	86.9	17.6	45.9	131,600	552
Nebraska	722,668	92.2	13.5	30.3	113,200	569
Nevada	827,457	90.8	42.4	8.4	283,400	861
New Hampshire	547,024	86.8	13.4	40.8	240,100	854
New Jersey	3,310,2785	92.6	10.5	5.65	333,900	935
New Mexico	780,579	86.9	22.9	25.0	125,500	587
New York	7,679,307	91.9	6.8	12.5	258,900	841
North Carolina	3,523,944	88.9	27.0	39.8	127,600	635
North Dakota	289,677	88.8	13.0	44.2	88,600	479
Ohio	4,783,051	92.9	13.3	22.7	129,600	613
Oklahoma	1,514,400	88.6	13.4	34.7	89,100	547
Oregon	1,452,709	91.8	21.9	21.3	201,200	689
Pennsylvania	5,249,750	91.0	10.4	23.0	131,900	647

Jurisdiction	Total Housing Units	Occupancy Rate (%)	Percent Built since 1990	Percent Rural Housing	Median Housing Value ($)	Median Gross Rent ($)
Rhode Island	439,837	92.9	8.7	9.0	281,300	775
South Carolina	1,753,670	87.5	25.9	39.5	113,100	611
South Dakota	323,208	89.8	16.2	48.1	101,700	500
Tennessee	2,439,443	91.5	23.5	36.3	114,000	583
Texas	8,157,575	90.6	20.7	17.5	106,000	671
Utah	768,594	91.2	25.9	11.7	167,200	665
Vermont	294,382	81.7	13.7	61.80	173,400	683
Virginia	2,904,192	92.9	20.0	27.0	212,300	812
Washington	2,451,075	92.7	21.7	18.0	227,700	741
West Virginia	844,623	87.2	15.5	53.9	84,400	483
Wisconsin	2,321,144	89.8	16.8	31.7	152,600	643
Wyoming	223,854	86.5	13.9	34.8	135,000	537

Note: All data from 2000 census
Source: U.S. Census Bureau, 2005.

Table 3-30. Economic Characteristics of the States

Jurisdiction	Gross State Product ($B)	Percent Change 2004-05	GSP Per Capita ($)	State Revenue Per Capita ($)	Revenue: Expenditure Ratio	Income Per Capita ($)	Unemploy-ment Rate (%)	Res. Elec. Bill ($ Avg. mo.)
Alabama	132	3	29,730	4,766.51	0.91	27,795	4.0	80.34
Alaska	31	0.5	47,657	13,453.17	0.91	34,454	6.8	91.17
Arizona	182	8.7	38,548	4,143.63	0.91	28,442	4.7	77.05
Arkansas	75	2.5	28,772	5,172.79	0.89	25,725	4.9	89.10
California	1,446	4.3	43,430	6,397.23	0.89	35,019	5.4	66.47
Colorado	187	4.1	44,787	5,015.63	0.78	36,063	5.0	55.69
Connecticut	173	3.7	50,816	5,578.38	1.00	45,398	4.9	88.42
Delaware	47	1.3	60,764	6,864.88	0.95	35,861	4.2	60.46
District of Columbia	70	4.5	12,2972	4,333.11	0.80	51,803	6.5	84.02
Florida	550	7.8	37,281	3,903.82	0.98	31,455	3.8	104.50
Georgia	320	4.5	39,999	5,098.47	0.81	30,051	5.3	84.47
Hawaii	46	4.8	37,968	4,752.00	0.95	32,160	2.8	109.41
Idaho	40	7.4	33,648	4,623.84	0.90	27,098	3.8	71.60
Illinois	499	2.1	40,216	4,322.69	0.94	34,351	5.7	63.93
Indiana	214	1.1	35,210	5,202.51	0.87	30,094	5.4	61.49
Iowa	103	1.7	34,700	4,039.56	1.01	30,560	4.6	68.45
Kansas	93	4.0	34,476	4,900.06	0.99	30,811	5.1	68.82
Kentucky	129	2.2	30,812	5,201.03	0.87	27,709	6.1	65.09
Louisiana	140	-2.0	30,289	6,319.34	0.88	27,581	7.1	100.17
Maine	39	1.0	31,171	5,108.57	0.89	30,566	4.8	75.03
Maryland	212	3.7	40,817	6,495.36	0.92	39,247	4.1	83.34

Jurisdiction	Gross State Product ($B)	Percent Change 2004-05	GSP Per Capita ($)	State Revenue Per Capita ($)	Revenue: Expenditure Ratio	Income Per Capita ($)	Unemploy-ment Rate (%)	Res. Elec. Bill ($ Avg. mo.)
Massachusetts	299	2.6	47,250	5,547.07	0.94	41,801	4.8	66.10
Michigan	365	0	34,478	5,828.57	0.97	31,954	6.7	55.50
Minnesota	211	1.3	42,673	5,291.65	0.93	35,861	4.0	61.09
Mississippi	72	1.2	24,492	4,569.52	0.84	24,650	7.9	71.30
Missouri	195	2.1	34,358	5,881.00	0.86	30,608	5.4	92.56
Montana	26	5.4	28,242	4,757.71	0.84	26,857	4.1	61.49
Nebraska	66	1.7	36,105	4,344.68	0.86	31,339	3.8	90.56
Nevada	88	8.2	48,335	4,753.39	0.92	33,405	4.1	67.08
New Hampshire	50	4.4	41,006	5,825.37	0.92	37,040	3.6	67.10
New Jersey	385	2.1	45,814	6,205.85	0.93	41,332	4.4	75.35
New Mexico	56	4.6	32,910	7,080.59	0.97	26,191	5.3	74.69
New York	867	3.3	45,692	5,195.69	0.84	38,228	5.0	51.26
North Carolina	314	3.9	38,314	8,220.21	0.61	29,246	5.2	87.15
North Dakota	21	4.6	32,512	6,676.28	0.77	31,398	3.9	81.72
Ohio	403	1.0	34,786	4,971.72	0.85	31,322	5.9	70.71
Oklahoma	100	2.9	29,209	6,819.47	0.77	28,089	4.4	80.76
Oregon	120	6.7	39,931	5,584.37	0.83	29,971	6.1	69.64
Pennsylvania	450	2.1	35,039	6,727.96	0.88	33,348	5.0	80.68
Rhode Island	38	2.0	36,777	5,060.02	1.01	33,733	5.0	68.88
South Carolina	127	3.5	30,993	5,011.18	0.77	27,172	6.8	94.45
South Dakota	27	3.5	36,657	4,059.19	0.93	30,856	3.9	69.17
Tennessee	200	1.6	35,697	4,030.37	0.85	30,005	5.6	82.60
Texas	813	4.3	40,549	5,439.01	0.82	30,222	5.3	109.02
Utah	76	5.8	35,451	6,928.49	0.91	26,606	4.3	50.69
Vermont	21	3.0	34,662	4,777.41	0.85	32,770	3.5	90.45
Virginia	304	5.6	44,372	5,652.64	0.93	35,477	3.5	78.34
Washington	245	3.7	40,597	6,416.63	0.85	35,299	5.5	65.61
West Virginia	47	3.2	25,272	6,314.18	0.82	25,872	5.0	63.14
Wisconsin	200	2.0	36,260	10,181.77	0.70	32,157	4.7	65.18
Wyoming	22	4.9	41,830	4,766.51	0.91	34,306	3.6	57.76

Note: All data from 2000 census

Source: U.S. Census Bureau, 2005 and 2004; U.S. BEA, 2005; U.S. BLS, 2005; EIA, 2002.

3.12 UTILITY INFRASTRUCTURE

This section describes the utility infrastructure that may be affected by carbon sequestration projects. It includes current and projected future growth in electricity transmission lines and natural gas transmission and distribution lines in the U.S. The distribution of wastewater treatment facilities at a national level is also discussed. The utility rights-of-way afforded by this infrastructure can serve as possible corridors for the installation of CO_2 pipelines that may be required to implement one or more carbon capture and sequestration technology projects.

3.12.1 Electricity Transmission Lines

The North American Electric Reliability Council (NERC) through its ten regional councils ensures the reliability of the North American electricity transmission system. Figure 3-29 shows the geographic areas covered by the ten NERC regional councils whose members account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, Mexico. In addition to the ten regional councils, the Alaska Systems Coordinating Council (ASCC), which covers the state of Alaska, is an affiliate NERC member.

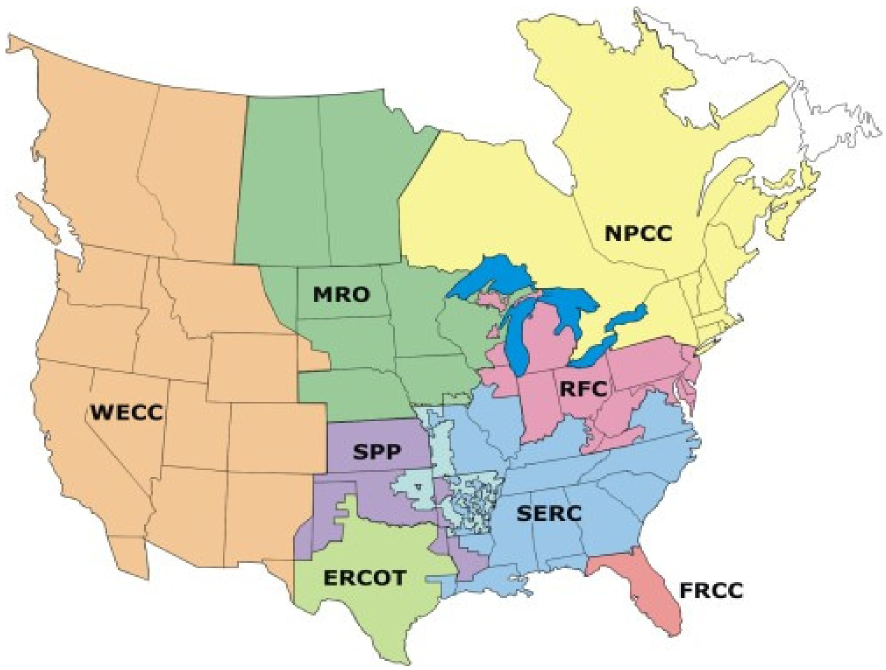
A breakdown of the total miles of high voltage (230 kV and greater) electricity transmission lines by NERC regions is shown in Table 3-31 (NERC, 2004, Alaska Energy Taskforce, 2003). A projection of planned increases is also included in the table. As of 2003, there were a total of 209,000 circuit miles within the NERC regions in the U.S., Canada, and Mexico. This includes about 161,000 miles spread across the 48 U.S. contiguous states and Alaska. More than 5,600 miles of new transmission (230 kV and above) are proposed for addition through 2008, with a total of about 10,325 miles added over the 2004–2013 timeframe. This represents a 5 percent increase in the total installed circuit miles of high voltage transmission lines in North America.

Table 3-31. Current and Planned High Voltage Transmission Circuit Miles in NERC Regions

NERC -Region	2003 Existing	2004–2008 Planned Additions	2009–2013 Planned Additions	2013 Total Projected
ASCC	760	NA[1]	NA[1]	760
ECAR	16,439	156	17	16,612
ERCOT	8,081	290	110	8,481
FRCC	6,894	360	81	7,335
MAAC	7,057	134	0	7,191
MAIN	6,195	374	260	6,829
MRO-U.S.	14,705	228	246	15,179
NPCC-U.S.	6,406	376	0	6,782
SERC	28,868	1,349	1,085	31,302
SPP	7,659	191	17	7,867
WECC-U.S.	58,400	1,573	1,582	61,555
Total U.S.	161,464	5,031	3,398	169,893
MRO-Canada	6,660	94	963	7,717
NPCC-Canada	28,961	258	38	29,257
WECC-Canada	10,969	270	252	11,491
Total Canada	46,590	622	1,253	48,465
WECC-Mexico	563	24	0	587
TOTAL NERC	208,617	5,677	4,651	218,945

[1] *NA=Not Available*

Source: NERC, 2004; Alaska Energy Taskforce, 2003.



Key:
ECAR – East Central Area Reliability Coordination Agreement
ERCOT – Electric Reliability Council of Texas, Inc.
FRCC – Florida Reliability Coordinating Council
MAAC – Mid-Atlantic Area Council
MAIN – Mid-America Interconnected Network, Inc.
MRO – Midwest Reliability Organization
NPCC – Northeast Power Coordinating Council
SERC – Southeastern Electric Reliability Council
SPP – Southwest Power Pool, Inc.
WECC – Western Electricity Coordinating Council

Source: NERC, 2007.

Figure 3-29. Map of NERC's Regional Reliability Councils.

3.12.2 Natural Gas Pipelines

Based on statistical data for 2003 from the Office of Pipeline Safety (OPS), there are about 2.2 million miles of pipelines in natural gas transmission and distribution service in the U.S. A breakdown of the total mileage in gas transmission and distribution is shown in Table 3-32.

Table 3-32. Breakdown of Total Miles of Natural Gas Pipelines by Service Type in 2003

Service Type	United States
Gas Transmission	304,001
Gas Distribution (Main)	1,097,910
Gas Distribution (Service)	754,361
TOTAL	2,156,272

Source: DOT, 2005.

Based on projected demand for natural gas in North America, about 45,000 miles of pipe will be required over the 2003 – 2020 time period. Approximately 35,000 miles will be new pipe while 10,000 miles will be needed to replace existing pipe. Of the 35,000 miles of new pipe, approximately 7,000 miles will be associated with bringing Alaskan and MacKenzie Delta gas to the lower 48 states. Approximately two-thirds of anticipated pipeline capacity built will be less than 24 inches in diameter. Such pipe will most likely be used to relieve local bottlenecks, connect new industrial customers, connect new power plants, or access new supply within a basin (INGAA, 2004). These new pipeline additions represent additional opportunities for utility rights-of-way that will be required for developing CO_2 pipeline infrastructure.

Table 3-33 provides information on natural gas pipelines in each state.

Table 3-33. Estimated Miles of Natural Gas Transmission in the Lower 48 States, 2004

State	Transmission Pipeline Mileage
Alabama	4,687
Arizona	5,989
Arkansas	6,201
California	11,669
Colorado	7,186
Connecticut	619
Delaware	231
Florida	4,636
Georgia	3,342
Idaho	1,567
Illinois	11,904
Indiana	4,679
Iowa	5,347
Kansas	15,251
Kentucky	6,776
Louisiana	18,155
Maine	607
Maryland/District of Columbia	959
Massachusetts	934
Michigan	9,688
Minnesota	4,431
Mississippi	9,484
Missouri	3,769
Montana	3,861
Nebraska	5,346
Nevada	1,465
New Hampshire	291
New Jersey	1,512
New York	4,726
New Mexico	6,628
North Carolina	2,474
North Dakota	1,873
Ohio	7,,612
Oklahoma	18394
Oregon	1,823
Pennsylvania	8,522
Rhode Island	100
South Carolina	2,265

State	Transmission Pipeline Mileage
South Dakota	1,242
Tennessee	4,273
Texas	59,109
Utah	3,016
Vermont	53
Virginia	2,428
Washington	2,070
West Virginia	4,729
Wisconsin	3,308
Wyoming	7,090
Total	**24,583**

Source: Tobin, 2005.

3.12.3 CO_2 Pipelines

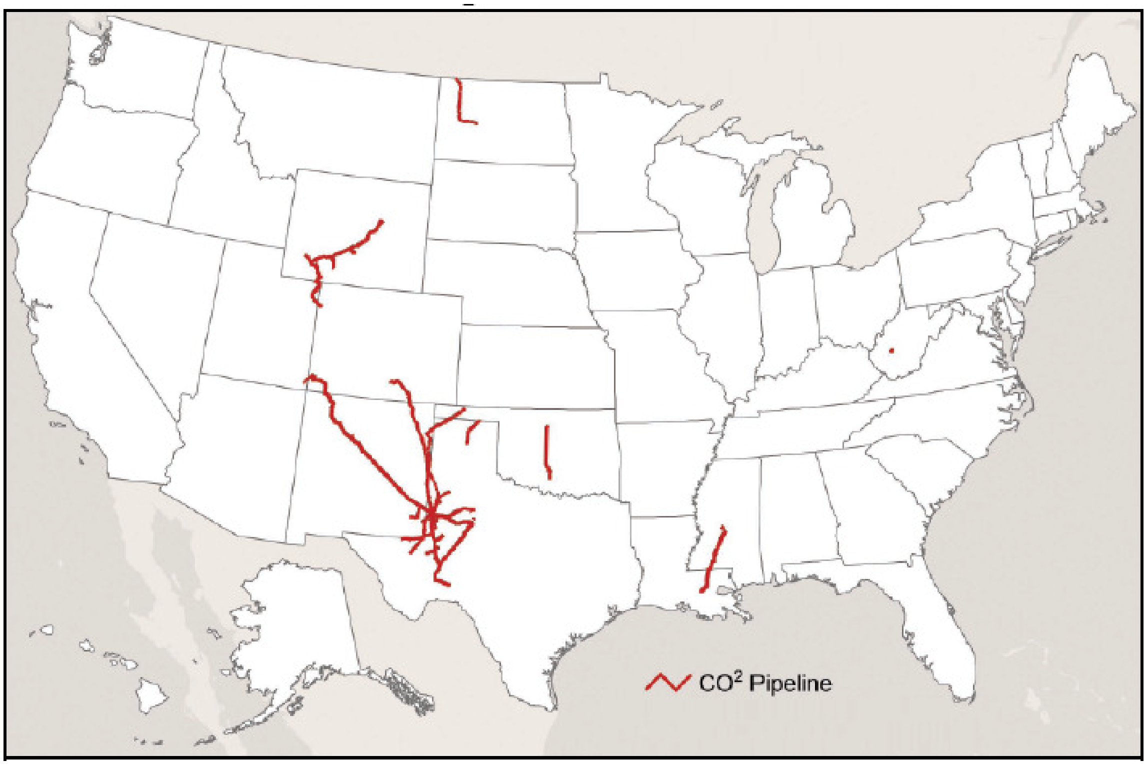
A list of major CO_2 pipelines currently being operated in the U.S. is shown in Table 3-34 and in Figure 3-30. There are almost 3,300 miles of CO_2 pipelines that are currently used to deliver CO_2 to EOR sites in the U.S. and Canada. The larger CO_2 pipeline networks deliver naturally occurring CO_2 from underground-sources at McElmo Dome and Sheep Mountain in Colorado, Bravo Dome in New Mexico, and Jackson Dome in Mississippi to EOR sites located in Texas, Oklahoma, New Mexico, Utah, Mississippi, and Louisiana. A smaller network connects sources of anthropogenic CO_2 obtained from gas processing facilities to EOR sites in Oklahoma, Texas, Wyoming, and Canada.

Table 3-34. Major CO_2 Pipelines in the United States

Name	Operator	Route	Length (miles)	Diameter (in.)
Anadarko pipeline extension	Anadarko	Baroil to Salt Creek, WY	125	16
Anton Irish	Oxy	Denver City to Anton Irish Field, TX	40	8
Bravo pipeline	BP	Bravo Dome, NM to Denver City, TX	218	20
Canyon Reef Carriers (CRC) pipeline	Kinder Morgan	McCamey to SACROC, TX	140	16
Comanche Creek	Kinder Morgan	Crane County to CBPL, TX	90	6
Centerline Pipeline	Kinder Morgan	Denver City to SACROC, TX	113	16
Central Basin pipeline (CBPL)	Kinder Morgan	Denver City Hub to McCamey, TX	140	26, 16
Chaparral	Chaparral Energy	Lateral off Transpetco line to Morrow fields, OK	23	6
Choctaw pipeline	Denbury Resources	Jackson Dome, MS to Bayou Choctaw field, LA	183	20
Cordona Lake	ExxonMobil	Lateral from CBPL to Cordona Lake, TX	7	6
Cortez pipeline	Kinder Morgan	McElmo Dome, CO to Denver City, TX	502	30
Dollarhide	Pure Energy	Lateral from CBPL to Dollarhide, TX	23	8
El Mar	KinderMorgan	Lateral between Dollarhide and El Mar, TX	35	6
Enid-Lindsey pipeline	Anadarko	Enid to Lindsey, OK	120	8
Este pipeline	Exxon Mobil	Denver City to Salt Creek, TX	119	12, 14
Exxon Wyoming CO_2 pipeline	Exxon Mobil	Shute Creek pipeline interconnect to Rock Springs and Baroil, WY	112	16, 20
Ford	KinderMorgan	Lateral between El Mar and Ford, TX	12	4
Llano Lateral	Trinity Pipeline	Connects Cortez pipeline to Llano, NM	53	12,8

Name	Operator	Route	Length (miles)	Diameter (in.)
McElmo Creek pipeline	Exxon Mobil	McElmo Dome to McElmo Creek, UT	40	8
Pecos County	KinderMorgan	McCamey to Yates field, TX	26	8
Raven Ridge	Chevron Texaco	Rock Springs, WY to Rangely, CO	125	16
Sheep Mountain I pipeline	BP	Sheep Mountain Field to Rosebud connection at Bravo Dome	184	20
Sheep Mountain II pipeline	BP	Rosebud connection to Denver City and onward to Seminole San Andreas Unit, TX	224	24
Shute Creek	ExxonMobil	LaBarge to Exxon Wyoming CO_2 pipeline interconnect.	30	30
Slaughter pipeline	ExxonMobil	Denver City to Hockley County, TX	40	12
Transpetco/Bravo pipeline	Transpetco	Bravo Dome to Postle field, OK	120	12.75
Val Verde pipeline	Petro Source	Connects gas processing facilities to CRC pipeline at McCamey, TX	83	10
Wellman	Wiser	Denver City to Wellman, TX	25	6
White Frost	Core Energy, LLC	Antrim gas plant to Dover field, MI	11	6
West Texas pipeline	Trinity Pipeline	Denver City to Reeves County, TX	127	12, 8
Weyburn pipeline	Dakota Gasification Company	Great Plains Synfuels plant in North Dakota to Weyburn field, Canada	205	14, 12

Source: Kindermorgan.com; Heddle et. al., 2003; IOGCC, 2005.



Source: U.S. DOT-NPMS, 2005

Figure 3-30. Major CO_2 Pipeline Systems in the United States

3.12.4 Water and Wastewater Treatment Facilities

Water and wastewater services in the U.S. are decentralized. There are about 54,000 community water systems that supply most of the nation's drinking water and about 16,000 wastewater treatment systems that provide sewer service. The infrastructure includes about 800,000 miles of water delivery pipelines and 600,000 – 800,000 miles of sewer pipelines. These systems vary in size and distribution. A majority of these utilities are small with 93 percent of community drinking water and 71 percent of wastewater systems serving 10,000 people or fewer (USGAO, 2004).

A breakdown by flow range and state of the total number of wastewater treatment facilities that are currently in operation in the U.S. (Table 3-36) is documented by the EPA (2003) in a Clean Watersheds Needs Survey (CWNS) report that is available at http://www.epa.gov/owm/mtb/cwns/2000rtc/toc.htm. The breakdown by flow range is reproduced in Table 3-36. As of 2000, there were a total of 16,255 wastewater treatment facilities treating about 35 billion gallons per day (gpd) of wastewater in the U.S. About 80 percent of these facilities have flow rates ranging between 1,000 to 1,000,000 gpd with total flow rates of about 2.6 billion gpd (7.5 percent of the U.S. total flow rate). About 19 percent are larger facilities with flow rates ranging between 1 – 100 million gpd and total flow rates of 21 billion gpd (60 percent of U.S. total). Less than 1 percent (about 50) of the total includes the largest facilities with operating flow rates exceeding 100 million gpd and total flow rates of about 11 billion gpd (32 percent of U.S. total).

Table 3-35. Breakdown of Operating Wastewater Treatment Facilities by Flow Range

Flow Range (GPD)	Existing Facilities in 2000		Total Flow	
	Number	Percent of Total	Million GPD	Percent of Total
1,000 to 100,000	6,583	40.5	290	0.8
100,001 to 1,000,000	6,462	39.8	2,339	6.7
1,000,001 to 10,000,000	2,665	16.4	8,328	23.9
10,000,001 to 100,000,000	487	3.0	12,741	36.5
> 100,000,000	46	0.3	11,201	32.1
Other	12	0.1	NA[1]	NA[1]
TOTAL	16,255	100.0	34,899	100.0

[1] *NA= Not Available; Flow data for these facilities were unavailable.*

Source: EPA, 2003.

Table 3-36 provides information on wastewater treatment facilities in each state.

Table 3-36. Breakdown of Wastewater Treatment Facilities in each State

State	Number of Facilities
Alabama	272
Alaska	45
Arizona	118
Arkansas	335
California	586
Colorado	311
Connecticut	91
Delaware	18
District of Columbia	1
Florida	277
Georgia	352
Hawaii	21
Idaho	168
Illinois	721

State	Number of Facilities
Indiana	404
Iowa	726
Kansas	634
Kentucky	224
Louisiana	355
Maine	137
Maryland	156
Massachusetts	126
Michigan	396
Minnesota	514
Mississippi	303
Missouri	678
Montana	194
Nebraska	462
Nevada	51
New Hampshire	85
New Jersey	156
New Mexico	55
New York	588
North Carolina	491
North Dakota	282
Ohio	765
Oklahoma	489
Oregon	207
Pennsylvania	779
Rhode Island	21
South Carolina	186
South Dakota	271
Tennessee	246
Texas	1,363
Utah	97
Vermont	81
Virginia	227
Washington	235
West Virginia	212
Wisconsin	592
Wyoming	96

Source: EPA, 2003.

3.12.5 Transportation

The U.S. transportation system carries over 4.7 trillion passenger miles of travel and 3.7 trillion ton miles of domestic freight generated by about 270 million people, 6.7 million business establishments, and 88,000 units of government. Rail and maritime transportation each account for over 11 percent of the tonnage carried.

Transportation investment and annual expenditures represent a significant element of our overall national assets and expenditures. American households, businesses, and governments spend over $1 trillion to travel 3.8 trillion miles and to ship goods 3.5 trillion miles each year. The net depreciated value of personal motor vehicles alone is $900 billion, and the value of roads and highways is estimated at over

$700 billion. When adjusted to formal definitions of the National Income Product Accounts, transportation accounts for 12 percent of Gross Domestic Product.

Summarized in the following are key aspects of the National Highway System and National Railroad Freight System.

3.12.5.1 National Highway System

On June 29, 1956, President Eisenhower signed the Federal Aid-Highway Act of 1956, which authorized the interstate highway system (later formally named the Dwight D. Eisenhower System of Interstate and Defense Highways). The Act authorized 41,000 miles of high quality highways that were to tie the nation together. Later, congressional action increased the length to 42,500 miles and required super-highway standards for all interstate highways.

The system was to be completed by 1975. It was conceived as a "pay as you go" system that would rely primarily on federally imposed user fees on motor fuels --- the federal user fee per gallon of gasoline was increased by one cent. The federal user fees would provide 90 percent of the cost of construction with the balance provided primarily by state user fees. The interstate highway system would incorporate approximately 2,000 miles of already completed toll roads.

The current National Highway System (NIH) consists of approximately 160,000 miles (256,000 kilometers) of roadway important to the nation's economy, defense, and mobility (Figure 3-31). The NHS includes the following subsystems of roadways (note that a specific highway route may be on more than one subsystem):

- Interstate : The Eisenhower Interstate System of highways retains its separate identity within the NHS.
- Other Principal Arterials: These are highways in rural and urban areas which provide access between an arterial and a major port, airport, public transportation facility, or other intermodal transportation facility.
- Strategic Highway Network (STRAHNET): This is a network of highways which are important to the U.S.' strategic defense policy and which provide defense access, continuity and emergency capabilities for defense purposes.
- Major Strategic Highway Network Connectors: These are highways which provide access between major military installations and highways which are part of the Strategic Highway Network.
- Intermodal Connectors: These highways provide access between major intermodal facilities and the other four subsystems making up the National Highway System.

In addition to being designed to support automobile and heavy truck traffic, interstate highways are also designed for use in military and civil defense operations within the U.S., particularly troop movements. One potential civil defense use of the Interstate highway system is for the emergency evacuation of cities in the event of a potential war. The Interstate Highway System has been used to facilitate evacuations in the face of hurricanes and other natural disasters.

Over 40 corridors have been designated as high priority corridors on the National Highway System (NHS) and are included in the 163,000-mile approved NHS as specific routes or general corridors. (Some of the corridors are part of longer high priority corridors.) Some of the corridors are entirely within a single State; some are multi-State corridors. (e.g., the Sarnia, Ontario, Canada to Lower Rio Grande Valley, Texas, corridor and the Sault Ste. Marie, Michigan, to Charleston, South Carolina, corridor).

Some of these corridors are described in detail in legislation while others are broadly defined. Figure 3-32 is a map showing the location of these high priority corridors.

3.12.5.2 National Railroad Freight System

In 2002, the freight railroad industry produced over 1.5 trillion ton-miles that generated revenue of $36.9 billion. The industry originated over 31 million carloads on a network consisting of nearly 142,000 miles of road. The industry employed over 177,000 employees. Figure 3-33 is a map of the U.S. railroad network.

Freight railroads in the U.S. move 42 percent of our nation's freight (measured in ton-miles) - everything from lumber to vegetables, coal to orange juice, grain to automobiles, and chemicals to scrap iron - and connect businesses with each other across the country and with markets overseas. They also contribute billions of dollars each year to the economy through investments, wages, purchases, and taxes.

There were 554 common carrier freight railroads operating in the U.S. in 2002, classified into five groups. Class I railroads are those with operating revenue of at least $272 million in 2002. Class I carriers comprise only 1 percent of the number of U.S. freight railroads, but they account for 70 percent of the industry's mileage operated, 89 percent of its employees, and 92 percent of its freight revenue. Class I carriers typically operate in many different states and concentrate largely (though not exclusively) on long-haul, high-density intercity traffic lanes. There are seven Class I railroads ranging in size from just over 3,000 to more than 33,000 miles operated and from 2,600 to more than 46,000 employees.

U.S. freight railroads employ approximately 177,000 people, the vast majority of whom are unionized. With average total compensation in 2002 of more than $80,000, freight railroad employees are among the nation's most-highly compensated workers.

By any measure of capital intensity, freight railroads are at or near the top among all major U.S. industries. From 1980 through 2003, Class I railroads spent more than $320 billion approximately 44 percent of their operating revenue - on capital expenditures and maintenance expenses related to infrastructure and equipment. Non-Class I carriers spent billions of dollars more. These massive expenditures help ensure that railroads have the capability to offer high quality, safe, and cost-effective service to meet the freight transportation needs of our nation.

Coal is the most important single commodity carried by rail. In 2002, it accounted for 44 percent of tonnage and 21 percent of revenue for Class I railroads. The vast majority of coal in the U.S. is used to generate electricity at coal-fired power plants. Coal accounts for half of all U.S. electricity generation, far more than any other fuel source, and railroads handle approximately two-thirds of all U.S. coal shipments.

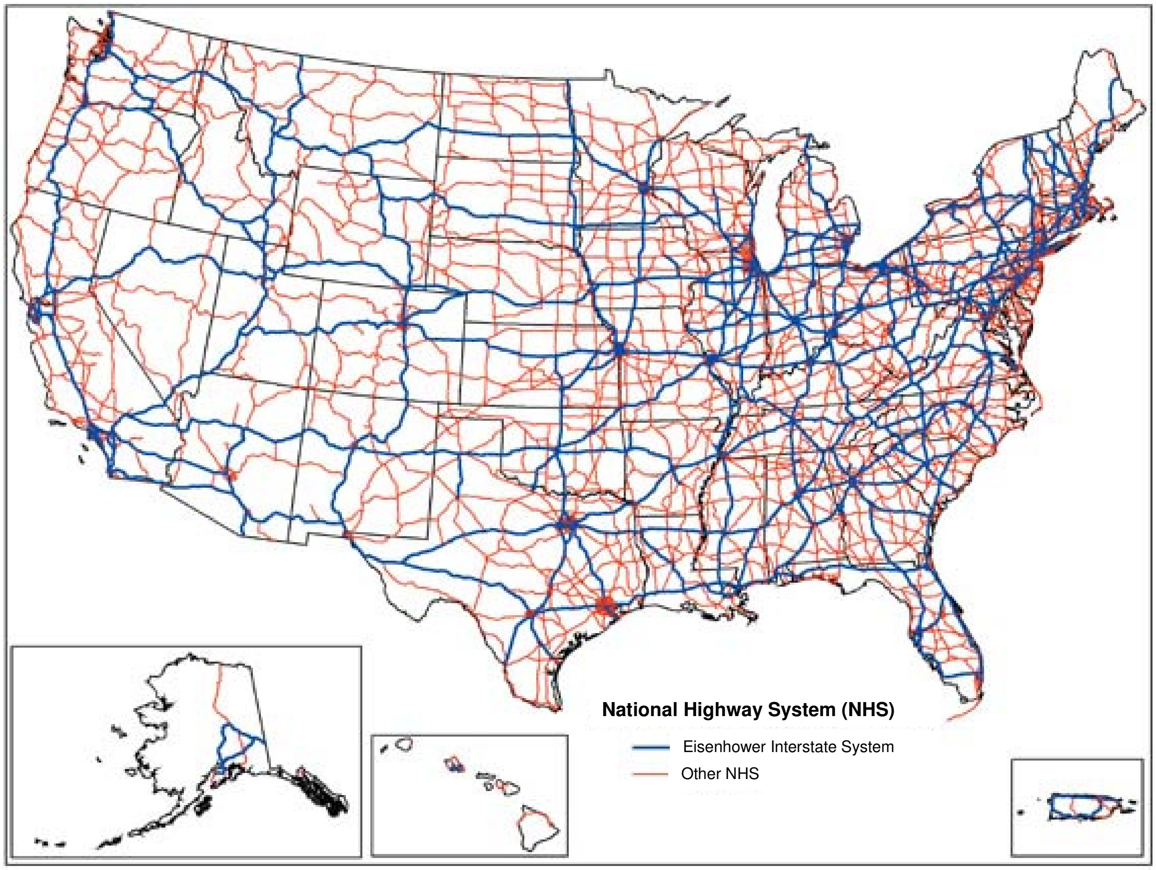
Table 3-37 provides transportation information for each state.

Table 3-37. National Highway System Miles and Rail Line Miles in each State

State	Miles of Highways	Miles of Rail Lines
Alabama	3,707	3,332
Alaska	2,111	506
Arizona	2,743	1,815
Arkansas	2,724	2,692
California	7,630	5,796
Colorado	3,580	2,530
Connecticut	963	543
Delaware	322	228
District of Columbia	83	24
Florida	4,364	2,840
Georgia	4,392	4,779

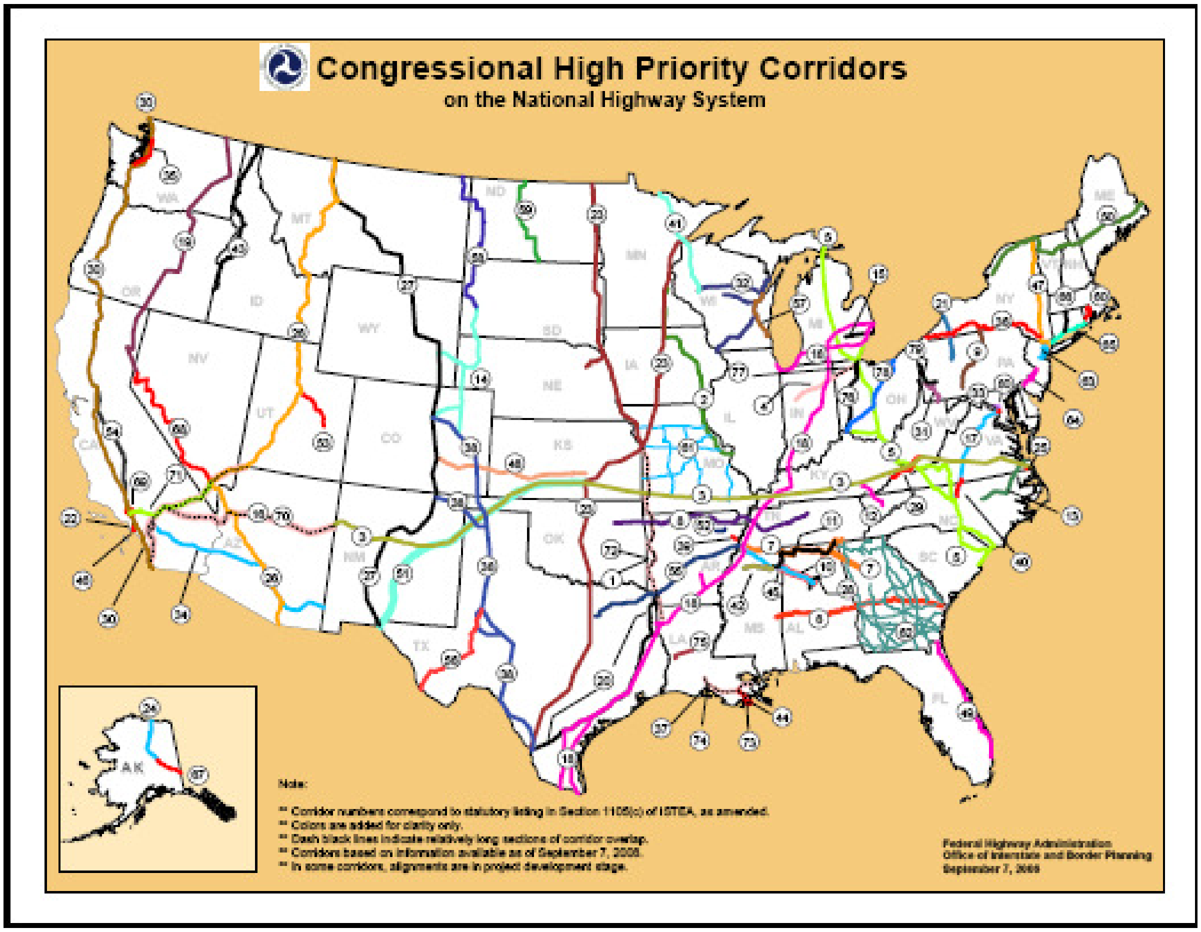
State	Miles of Highways	Miles of Rail Lines
Hawaii	347	0
Idaho	2,369	1,529
Illinois	5,703	7,338
Indiana	2,883	4,192
Iowa	3,216	3,946
Kansas	3,781	4,936
Kentucky	2,891	2,640
Louisiana	2,604	2,971
Maine	1,289	1,148
Maryland	1,457	759
Massachusetts	1,971	1,097
Michigan	4,759	3,590
Minnesota	3,969	4,589
Mississippi	2,823	2,481
Missouri	4,458	4,122
Montana	3,875	3,269
Nebraska	2,985	3,478
Nevada	2,132	1,202
New Hampshire	825	421
New Jersey	2,076	917
New Mexico	2,935	1,703
New York	5,151	3,553
North Carolina	3,790	3,250
North Dakota	2,727	3,593
Ohio	4,404	5,179
Oklahoma	3,364	3,228
Oregon	3,750	2,481
Pennsylvania	5,485	5,060
Rhode Island	269	102
South Carolina	2,624	2,300
South Dakota	2,938	1,837
Tennessee	3,255	2,609
Texas	13,330	10,246
Utah	2,178	1,452
Vermont	698	568
Virginia	3,491	3,236
Washington	3,423	3,179
West Virginia	1,823	2,258
Wisconsin	4,172	3,400
Wyoming	2,950	1,862

Source: FHWA, 2004; Association of American Railroads, 2004.



Source: Federal Highway Administration, http://www.fhwa.dot.gov/hep10/nhs/

Figure 3-31. National Highway System



Source: FHWA, 2007.

Figure 3-32. Map of High Priority Corridors

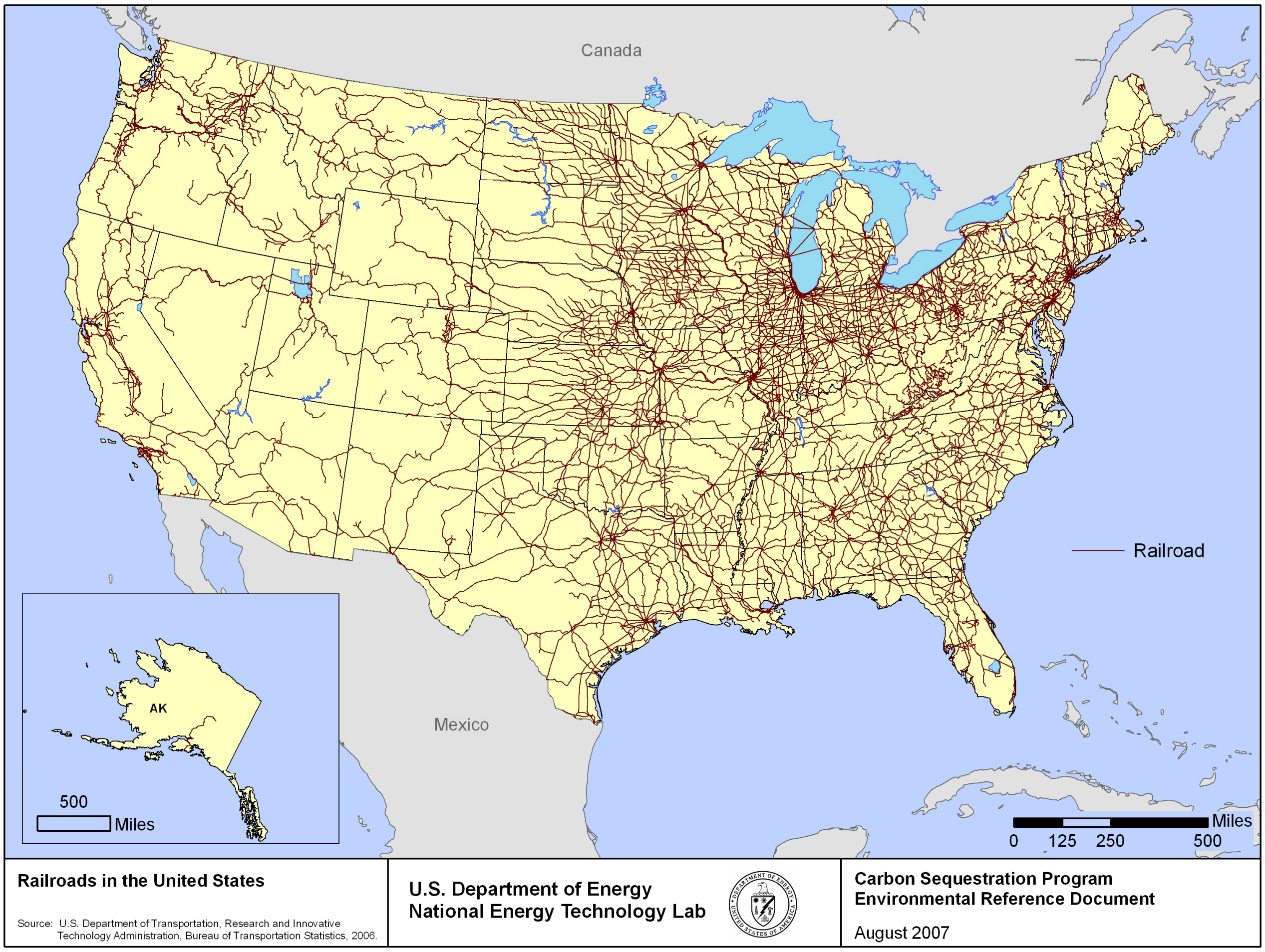


Figure 3-33. Rail Network of the United States

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4.0 IMPACTS OF PROGRAM TECHNOLOGIES

4.1 INTRODUCTION

This chapter describes the potential environmental impacts resulting from implementing Program technologies. For each environmental resource, the following topics are addressed in this chapter:

- **Impact Considerations** – Describes the thresholds, features or outcomes that were considered when assessing the potential of a technology to cause impacts. The severity of an impact relates to the value of affected resources, as well as the magnitude and frequency of the potential impact. Section 4.1.1 discusses the methodology in further detail.

- **Generalized Siting and Operational Impacts of Technologies** – Describes the potential impacts of each respective technology. The discussions are intended to provide the reader with a sense of the typical issues, concerns, and potential impacts that may be expected from siting and operation of a project involving a particular technology.

- **Mitigation of Potential Adverse Impacts** – Provides guidance with respect to significant impacts that should be avoided during site selection for future projects and recommends Best Management Practices (BMPs) and other measures that should be followed to mitigate potential adverse impacts during project planning, design, construction, and operation.

- **Regional Considerations** – Describes factors related to general environmental conditions in states that may create special concerns for the siting and operation of various technologies. Such conditions may relate to climate factors and other constraints that impose critical limitations or increased sensitivity for specific resources. The basis for environmental impacts includes the settings for all 50 states.

- **Summary of Potential Impacts** – Provides a graphic representation to summarize the potential impacts of each model project with respect to the considerations presented at the beginning of each section.

4.1.1 Impact Assessment Methodology

In this chapter, impact levels or ranges were assigned to each resource criteria for each individual technology. The following impact levels and their definitions were used:

- **Negligible Impact** – The impact is neither noticeable nor perceptible. Little or no change to environmental conditions is expected. For example, operations of new systems or technologies would have negligible impacts if they operate within industry and regulatory standards, meet BMPs, and conform to relevant environmental permit conditions. Processes where environmental degradation would be strictly controlled or fully mitigated, or would not interact with environmental resources could also result in negligible impacts.
- **Minor Adverse Impact** - The impact would be short-term and/or localized. The impact would fall within acceptable permit or regulatory limits, or would occur very infrequently, as in the case of a mishap. The duration of short-term impacts may include the timeframe for construction of a system, such as in the case of land disturbance for the installation of pipeline systems. Localized impacts would generally be those that fall within 1 mile of the footprint of the associated action. Exceptions to the definition of localized impacts will be discussed in the subsequent resource sections.

- **Moderate Adverse Impact** – The impact would be short-term and widespread or long-term and localized. The impact would result in discharges within acceptable permit limits, could be mitigated through BMPs or operational controls, or would occur very infrequently as in the case of a mishap. Widespread impacts are defined as occurring beyond limits defined for localized impacts. Long-term impacts are defined as exceeding the duration of short-term impacts.
- **Significant Adverse Impact** – The impact would be long-term and widespread. The impact would result in violation of environmental statutes and regulations, despite mitigation measures.
- **Beneficial Impact** – The impact would enhance or protect environmental resources, by the prevention of discharges that would normally occur otherwise, restoration of previously degraded environments or by creating a socio-economic benefit.

4.2 ATMOSPHERIC RESOURCES

This section describes the potential impacts to atmospheric resources (air quality and GHG reduction) that could occur during the implementation of carbon sequestration technologies. The atmospheric resources that could be affected by sequestration technologies are described in Section 3.2. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.2.1 Impact Considerations

Potential impacts on air quality have been assessed using the considerations outlined below and the definitions found in Section 4.1.1. Short-term impacts for atmospheric resources are defined as impacts occurring during the construction timeframe. Localized impacts for atmospheric resources are defined as those occurring within 25 miles of the relevant source.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- violate a NAAQS primary standard or contribute substantially to existing or projected violations.
- degrade air quality locally, regionally, nationally.
- cause air pollution that would increase the hazard quotient or cancer risk to the public.
- conflict with or obstruct implementation of a local or regional air quality management plan.
- create objectionable odors affecting site personnel or neighborhoods beyond the site boundary.
- substantially increase greenhouse gas emissions.

4.2.2 Regulatory Framework

Geologic sequestration technology is targeted at the large-scale reduction of CO_2 emitted into the atmosphere from anthropogenic sources. There are currently no regulatory limits on CO_2 emissions from point sources under the federal Clean Air Act, although some states are imposing their own CO_2 reduction goals as described in Appendix A. There are also no air permit regulations at the state or federal level regarding the transport of compressed CO_2 or the injection of CO_2 underground. As carbon sequestration technologies advance, a regulatory framework could be required for permitting and monitoring potential air emissions or releases attributable to CO_2 storage, transmission and injection.

CO_2 releases or leaks from geologic formations are unlikely to occur if proper project planning and formation characterization are conducted. Catastrophic releases of naturally occurring CO_2 are usually associated with areas of volcanic activity. In such cases, CO_2 finds its way to the land surface where, due to its heavier-than-air density, it pools near the ground in high concentrations. Near these volcanic areas, wildlife, plant life and humans have died from asphyxiation when CO_2 displaces oxygen. Asphyxiation can occur when the atmospheric oxygen is less than 16 percent (Rice, 2004). Because the sudden release of a large quantity of CO_2 can have ground-level impacts on nearby flora, fauna and humans, monitoring for leaks in and around pipelines and around injection points is an important consideration of any system design. Identifying and properly abandoning obsolete wells in the area of influence for geologic sequestration projects is also an important step to prevent unintentional CO_2 leaks. Transmission piping and wells should be located to allow for adequate dispersion of CO_2 (away from populated areas and environmentally sensitive areas) in the event of an accidental release.

In general, impacts on atmospheric resources or air quality from the implementation of carbon sequestration technologies would be related to the types of technologies used, intensity of construction activities that could increase airborne dust and tailpipe emissions, the potential release of chemicals used to convert or capture CO_2, the potential release of CO_2 or other gases during transfer or transportation via truck or pipeline, emissions from compressors and other equipment that are needed to transport and inject CO_2 underground, and the overall effectiveness and potential of technologies to reduce GHGs and other air pollutants.

Overall, carbon sequestration projects would need to consider applicable air quality laws and regulations at the federal, state and local levels to determine applicable permitting requirements. A list of federal air quality laws and regulations is provided in Table 4-1. For example, stationary sources of air pollution, such as generators, compressors and heating units used in the distribution and injection of CO_2 in geologic formations, would need to conform to applicable New Source Performance Standards. While most carbon sequestration programs may be implemented by the private sector, projects that receive federal funding in whole or in part would be required to conduct a clean air act conformity analysis under 40 CFR 51 Subpart W.

Table 4-1. Major Laws, Regulatory Requirements and Plans for Air Quality

Law/Regulation	Key Elements and Thresholds
National Ambient Air Quality Standards (NAAQS) 40 CFR 50	Primary and secondary standards designed to protect the public health and welfare. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. The EPA Office of Air Quality Planning and Standards (OAQPS) has set NAAQS for six principal pollutants, which are called "criteria" pollutants: carbon monoxide, lead, nitrogen oxides (NO_X), particulate matter, ozone and sulfur oxides (SO_X). Areas that experience ambient air levels of one or more of these criteria pollutants above the NAAQS are deemed to be in "non-attainment" and Regional Air Quality Conformity rules must be evaluated for new projects within the area.
Prevention of Significant Deterioration (PSD) 40 CFR 52.21	Prevent major sources in "unclassified" or "attainment" areas from creating large ambient impacts in excess of PSD increment standard and impaired visibility. Divide the U.S. into two classification categories: Class I (public lands that have special protection under the CAA) and Class II (remainder of the U.S.) Triggered if emissions of a single regulated pollutant equals or exceeds 250 tons per year, or 100 tons per year for each of the 28 major source categories.
New Source Review (NSR)	Federal preconstruction permitting program incorporating both NSR (applicable to sources of pollutants for which the area is nonattainment) and PSD (for major sources in other areas) to prevent new sources of emissions from deteriorating air quality beyond acceptable levels.
National Emission Standards for Hazardous Air Pollutants (NESHAPs) 40 CFR 61 and 63	Regulated emissions of 188 hazardous air pollutants (HAPs).
New Source Performance Standards (NSPS) 40 CFR 60	New source performance standards apply to new sources in designated source categories.
Title V Operating Permit 40 CFR 70 and 71	Operating permit program assures compliance with standards, recordkeeping, testing, and compliance at major sources of criteria and HAP emissions. Requires a Federal Operating Permit for major sources of regulated pollutants and a compliance plan for meeting each regulatory requirement. Designation of a major source is contingent on the attainment status of the air basin.

Law/Regulation	Key Elements and Thresholds
Determining Conformity of General Federal Actions to State or Federal Implementation Plans 40 CFR 51 Subpart W	All federal actions must conform to the applicable State Implementation Plan (SIP). Only pollutants for which the area is classified as nonattainment are included in the conformity determination. All construction related and non-permitted sources of emissions must be included in the conformity determination. If annual emissions exceed the significance threshold, a full conformity analysis is performed to ensure the project would not contribute to violation of the SIP. Modeling, offsets, and/or additional mitigation measures can be used to help the project conform.

4.2.3 Generalized Siting and Operational Impacts of Technologies

4.2.3.1 Post-Combustion Capture

Post-combustion capture projects would be retrofitted to existing, or added to proposed, fossil fuel combustion facilities. Combustion of fossil fuel results in emissions of CO_2 at a rate of 5 to 15 percent of the exhaust stream (Benson, 2004). Section 2.5 provides example model project descriptions that indicated the potential capture rate for small and moderately sized projects.

The ability to capture CO_2 at its point source would result in improved air quality and a reduction in GHGs. Some other pollutants, such as SO_x, NO_x, and PM, would be captured in the CO_2 stream. However, according to model project estimations, other pollutants from the post-combustion capture process would account for less than 0.5 percent of the total composition of the captured gas. Because the side reactions of SO_x and NO_x with amines tend to form soluble salts, thus consuming expensive reagent solvent and potentially creating additional waste streams, an optimal site selection criterion for application of these technologies would be for the existing coal-fired power plant to already be equipped with flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems for SO_2 and NO_x control, respectively.

This technology could potentially be used throughout the country; however, regional differences are difficult to predict. Therefore, the location of probable sinks for CO_2 and their proximity to existing sources would likely result in regional differences in the degree of implementation.

Another consideration is that the need to transport solvent (amine solution) in large quantities to the project site and to remove process related wastes (sludge and spent carbon) would result in increased traffic related emissions. These emission increases could potentially be reduced by transporting raw materials and wastes by rail wherever feasible.

The post-combustion capture process could cause minor adverse impacts in the form of increasing the emissions of regulated air pollutants, associated with the expected compression and transport operations that would follow the capture process. The capture process would have negligible impacts in terms of toxic and hazardous air pollutants, air quality management plans, and objectionable odors, as the process would not cause new air pollutants to be emitted. The process is designed to capture CO_2, resulting in a beneficial impact in the category of unregulated air pollutants.

4.2.3.1.1 Comparison of Power Plant Emissions with and without Carbon Sequestration

To illustrate the difference in air emissions between a conventional coal-fired power plant and one with CO_2 capture and sequestration, baseline air emissions from four conventional coal-fired power plants ranging from 299 to 358 MW were analyzed (see Table 4-2). Then the emissions anticipated from a similar plant with CO_2 capture, compression, transport and injection into a geologic formation were estimated (see Table 4-3). It is estimated that the CO_2 capture process removes 90 percent of the plants emissions. However, the equipment used to compress, transport and inject the CO_2 (which could be fossil-fueled) may emit additional air pollutants. The net emissions from the entire CO_2 sequestration process were then compared with the emissions from the plant without CO_2 capture. In this example, it is estimated that 83 percent of CO_2 emissions would be avoided under the sequestration process. However, NOx emissions would be 12 times greater overall under the sequestration option (assuming model project parameters for coal seam sequestration) when compared to the emissions of the power plant alone. Under this CO_2 sequestration example, the approximately 1,800,000 tons/year of CO_2 releases are avoided, while NOx releases would increase by approximately 40,000 tons/year. The amount of NOx released could be reduced through use of electric-powered equipment or low-NOx fossil-fueled equipment.

Table 4-2. Air Emissions from Coal-Fired Power Plants

Representative Power Plant (EIA, 2005, EPA, 2005)	**Nameplate Capacity** (MW)	**Coal Type**	**CO_2 Emissions** (tons CO_2 per year)	**NO_x Emissions**(tons per year)	**SO_2 Emissions** (tons per year)
Will County, IL Unit 3	299	Sub bituminous	1,246,847	1,180	2,575
HL Spurlock, KY Unit 1	305	Bituminous	2,253,244	4,632	18,589
Naughton, WY Unit 3	326	Bituminous	2,546,225	4,595	4,462
Colstrip, MT Unit 1	358	Bituminous	2,763,954	5,370	7,089
Average	322		2,202,568	3,944	8,179

Table 4-3. Comparison of Power Plant Emissions, With and Without Carbon Sequestration

Case (nominal 300 MW plant)	**CO_2 Emissions From Power Generation And Carbon Capture** (tons CO_2 per year)	**Other Air Emissions From Power Generation** (tons per year)	**Air Emissions From CO_2 Compression And Transport** (tons per year)	**Air Emissions from CO_2 Injection at a Coal Bed Methane Site** (tons per year)	**Total Emissions (tons per year)**
Example Coal Fired Power Plant with Carbon Capture	220,257	NOx 3,944 SO_2 8,179	CO_2 150,584 NO_x 44,336 SO_2 (NC)	CO_2 5,052 NOx < 1 SOx (NC)	CO_2 375,893 NOx 44,336 SOx 8,179
Example Coal Fired Power Plant without Carbon Capture	2,202,568 (see Table 4-2)	NOx 3,944 SO_2 8,179	None	None	CO_2 2,202,568 NOx 3,944 SOx 8,179

Note: NC means “not calculated”

4.2.3.2 CO_2 Compression and Transport

Compression and transport of CO_2 are well-established technologies that are used routinely for sequestration, beverage carbonation, and fire suppression (Benson, 2004). Uncontrolled releases of CO_2 from tanks and pipelines can be prevented through safety procedures, pressure testing of vessels and lines automated shut-off valves. Detection of releases can be improved by adding chemical odorants, like those added to natural gas, which would be especially beneficial around more populous areas (Heinrich, et. al, 2003).

The transport of CO_2 both by truck and by pipeline would contribute somewhat to air pollution and would generate additional CO_2 over the life of the project. Internal-combustion engine compressors would generate the majority of air pollutants including CO_2. It is likely that equipment to compress and pump CO_2 would require air permits. Other components of pipeline transport would include intercoolers, dehydrators, and water knockouts. Collectively, these stationary sources of air emissions for each pipeline project may meet the definition of a major source under the Prevention of Significant Deterioration (PSD) standard. Although trucks are considered mobile sources and their emissions do not fall under New Source Review regulations, their emissions would be counted in any Clean Air Act conformity analysis performed for federally funded projects. The decision to truck CO_2 or to construct a pipeline would likely be dictated by project quantities and economics. For small field validation-scale projects, trucking CO_2 to underground injection sites is expected to be the simplest and least expensive transport option. However, a larger-scale project justifies the construction of pipelines.

> Highest risk areas for leakage of CO_2 back to the atmosphere are associated with the injection wells, abandoned wells that could provide short-circuits to the surface, and inadequate characterization of the storage site (e.g., undetected faults).

The use of gas-fired compressors and heaters would introduce new sources of criteria pollutant emissions. However, impacts to air quality would be minor because it is assumed that equipment would conform to applicable air quality regulations and BACT. The compression and transport process would not introduce toxic or other hazardous air pollutants, nor create objectionable odors. Assuming all relevant air permits would be obtained, the process would not impact air quality management plans. The compression and transport process is a key element of geologic sequestration of CO_2. Subsequently, the process would have a beneficial impact towards reducing greenhouse gas emissions.

4.2.3.3 Sequestration in Coal Seams

Air impacts from sequestration in coal seams are associated with both construction and operation aspects of the project. Construction activities that may contribute to short-term air emissions include land clearing, providing access roads to the project site, drilling wells, installing CO_2 pipeline to wells, installing equipment, and running utilities to the site. To operate the system, gas-fired heaters would be employed at the well head.

The highest probability risk areas for leakage of CO_2 back to the atmosphere are associated with the injection wells, abandoned wells that provide short-circuits to the surface, and inadequate characterization of the storage site, such as not detecting faults (Benson, 2004). Leaks can be detected through monitoring systems at the wells and by deploying surface-flux monitoring of CO_2. See Section 2.2.3 on monitoring, mitigation and verification (MM&V) techniques.

For the reasons cited under the compression and transport process (4.2.3.2), the process of sequestering CO_2 in coal seams would have:

- a minor adverse impact with regard to increases in regulated air pollutants (due to use of gas-fired compressors and heaters);
- a negligible impact with regard to release of toxic and hazardous air pollutants;
- a negligible impact on air quality management plans;
- a negligible impact with regard to causing objectionable odors; and
- an overall beneficial impact by reducing greenhouse gas emissions.

4.2.3.3.1 Air Permitting for Coal Bed Methane (CBM) Projects

Carbon sequestration in coal seams would utilize similar equipment to that used in traditional CBM recovery projects. Therefore, air permitting requirements for carbon sequestration in coal seams (with or without CBM production) should be similar to those at existing CBM project sites. Stationary air emission sources associated with general CO_2 transport and compression (prior to injection) that are found under Section 4.2.3.2 "CO_2 Compression and Transport" would be included in the permitting of coal seam sequestration projects.

The process of CBM extraction requires the construction and operation of wells to access the gas and compressor stations to extract the gas. The compressor stations consist of various pieces of equipment with the potential to emit pollutants at varying levels depending on equipment capacities. In addition, the facility may incorporate a CBM powered generator (well-head generator) located on top of the well to generate electricity. In these cases, the generator would also be a source of pollutant emissions. A typical compressor station harvesting CBM will incorporate from 1 to 3 compressor engines varying in power from 100 to 500 hp. Operation of these natural gas fired engines results in the emission of regulated air pollutants including CO, NO_x, VOCs, SO_x, and PM-10 (Montana DEQ, 2005).

As an indicator of the types of air permit conditions that may be required for coal seam carbon sequestration projects, the Record of Decision for the Montana Statewide CBM EIS outlined the following conditions and mitigation procedures (Montana DEQ, 2003):

- *"Natural gas-fired field compressors, serving groups of wells, are generally permitted as minor sources. Best Available Control Technology (BACT) emission limits are established at the time of permit issuance and are established on a case-by-case basis.*

- *The larger scale compressors, serving several field compressors, will likely be permitted as major sources. BACT emission limits will be established for each compressor on a case-by-case basis.*

- *By administrative rule and, typically, by permit, reasonable precautions must be taken to control fugitive dust. Generally, opacity of emissions of airborne particulate matter is limited to less than 20 percent. Operators are required to keep fresh water and/or chemical dust suppressant available for the purpose of controlling fugitive dust.*

- *In addition, at least one regional-scale ambient monitoring station will be established and maintained. Criteria pollutants that will be monitored are NO_x, O_3, and PM-10. Data gathered by the monitoring program will be used to model cumulative impacts."*

Similarly, in Wyoming, CBM recovery projects require NAAQS analysis for compliance with NO_x standards. This analysis requires using the ISCST3 model and 7.5 minute Complex Terrain Data, using at least one year of on-site meteorological data (Wyoming, 2000). In addition, permits for generators operating at CBM well sites are required. New generators must also meet Best Available Control Technology (BACT), which at a minimum meets EPA/California certified emissions. However temporary diesel- or gas-fired generators may operate for up to 6 months under a waiver issued by the state (Wyoming, 2001).

The implementation of coal seam sequestration projects would require permitting of applicable source equipment in accordance with local, state and federal clean air requirements. To minimize air pollution associated with this technology, equipment should conform to the BACT.

Projects would require permitting of applicable source equipment, such as compressors and generators, in accordance with local, state and federal clean air requirements. To minimize air pollution, equipment should conform to the Best Available Control Technology (BACT).

4.2.3.4 Sequestration in Depleted Oil and Gas Reserves

Air impacts and permitting associated with sequestration in depleted oil and gas reserves would be similar to those for coal seams. However, due to the potential for a larger number of wells and abandoned wells at existing oil and gas reserves, the possibility for leakage of CO_2 is somewhat greater. Careful site selection and review of all wells or other surface conduits in the area must be conducted when designing a sequestration system at an oil or gas reserve.

The impacts to air resources for EOR would be similar to those for the compression and transport process.

4.2.3.5 Sequestration in Saline Formations

The impacts to air resources for saline formation sequestration would be similar to those for the compression and transport process.

4.2.3.6 Sequestration in Basalt Formations

Air impacts and permitting associated with sequestration in basalt formation would be similar to those for coal seams, and operational air impacts would generally relate to emissions from compression, transport and injection equipment. However, as CO_2 may react with the basalt causing mineralization, the long-term potential for leakage of CO_2 would be less than other geologic sequestration methods.

The impacts to air resources for basalt formation sequestration would be similar to those for the compression and transport process.

It is possible that the dissolved CO_2 would undergo a mineralization reaction with the calcium, magnesium, and iron silicates within a basalt formation producing carbonate minerals and amorphous quartz.

4.2.3.7 Terrestrial Sequestration-Reforestation

Many terrestrial sequestration projects involve planting of trees on a large scale. Terrestrial sequestration generally will not have air permitting issues, unlike the other CO_2 transport and geologic sequestration technologies.

Planting of trees or other plant material may involve use of heavy machinery for land clearing, grading, tilling, fertilizing, spreading of seed or other mechanized planting methods. The air emissions associated with these activities would be short-term and within existing air regulations.

As discussed below, the ability of forests to sequester carbon would be greatly dependent on a variety of factors, such as adverse weather events (drought, hurricanes), forest fires, air pollution, global warming, insect damage and/or tree-disease. Discussion of the potential rates of sequestration possible per acre of planting is discussed in Section 2.5. Under adverse conditions or as trees reach the end of their natural lifespan, some or all of the carbon captured by forests could be reversed (released) back into the atmosphere.

Terrestrial reforestation projects would have negligible impacts in terms of regulated air pollutants, toxic and hazardous air pollutants, air quality management plans, and objectionable odors. Reforestation would have a beneficial impact on unregulated air pollutants by taking up additional CO_2 from the air.

4.2.3.7.1 Effects of Climate Change and Natural Events on Sequestration in Vegetation

Climatic conditions can greatly influence the ability of vegetation to grow and perform photosynthesis, which directly affects the amount of carbon that plants can sequester (Watson et al., 2000). Plants do not grow in the winter in non-tropical regions; therefore, carbon uptake occurs from spring through fall in these areas (Ramanujan, 2002). Also, during the winter there is a loss of carbon back to the atmosphere as shed leaves and other plant material decomposes (ScienceDaily, 2002). Relatively warm early-spring temperatures can cause earlier leaf emergences by plants, which allows a longer growing season and an increased amount of carbon sequestered (Chen et al., 1999). Any climatic conditions, such as drought and cloud cover, that restrain elements necessary for plant growth during the growing season (water, light, etc.) will inhibit the amount of carbon that can be sequestered in vegetation (Hanson, 2001). Hurricanes and other major storm events in forested areas can have a major negative effect on carbon sequestration because they leave large amounts of dead trees in their wake that decompose and subsequently release the carbon that was stored in them back into the atmosphere (ScienceDaily, 2002). Other natural events, such as forest fires, can also reverse carbon sequestration in soils and trees by releasing stored carbon back into the atmosphere (EPA, 2005).

4.2.3.7.2 Effects of Air Pollutants on Tree Health

Trees sequester many pollutants from the atmosphere, including NO_2, SO_2, O_3, CO, and PM-10 (American Forests, 2005). However, high levels of air pollution are known to cause stress in trees and other plants, markedly decreasing their ability to ward off disease and pests and can limit their rate of growth.

Nitrogen deposition can degrade forest ecosystems by increasing sensitivity to frost, reducing net primary production, and leaching of nutrients, especially in areas where soil nitrogen levels are high and have reached, or are approaching, saturation. In a study of 4 areas of the northeastern U.S., the areas with the greatest frequency of problems from forest insects and disease also receive the highest deposition of sulfur and nitrogen and/or have the highest annual exposure to ground-level ozone (EMAN, 2003).

Forests have been predicted to grow faster under increased levels of CO_2 and so fix more carbon than possible under ambient conditions. However, along with the increasing concentrations of CO_2 in the atmosphere are increasing concentrations of tropospheric ozone. O_3 damages plant foliage and reproductive systems and adversely affects the growth processes. The impact of the interaction between increased concentrations of both atmospheric CO_2 and O_3 on forests can be varied, but is relatively unknown. Current research suggests that the presence of elevated concentrations of ozone will likely negate the potential for increased growth and carbon sequestration from higher concentrations of CO_2 (EMAN, 2003).

Further evidence of the uncertain effects of global climate change on carbon sequestration is found in a study of the interaction of forests exposed to SO_2 emissions. Boreal forest sites (northern forests generally dominated by coniferous trees) exposed to SO_2 captured drastically less CO_2 than control forests. It was found that SO_2 pollution affected trees even in remote regions, suggesting that an extensive region of the boreal forest may be impacted. Given that the boreal forest composes a large proportion of the estimated global forest carbon sink, the lowered carbon sequestration capacity related to SO_2 pollution may be globally significant (EMAN, 2003).

The interaction of elevated CO_2 and O_3 levels also can also affect forest pest feeding and larval growth as well as the chemical composition and defensive qualities of foliage. As a result, the incidence and severity of insect attack and disease outbreak may increase. One study showed sap-feeding aphids were five times more abundant on aspen species under high O_3 conditions than control plots, while natural number of enemies of the aphids where halved (Percy et al. 2002). Under both high ozone and CO_2, the aphids tripled in numbers while their enemies increased just slightly. In addition, trees may also be under considerably more stress in a changed climate leaving them more susceptible to insects and diseases, than they are currently, thus reducing any net benefit of increased temperature on carbon sequestration in forests (EMAN, 2003).

Trees can sequester many pollutants from the atmosphere. However, high levels of air pollution are known to cause stress in trees, markedly decreasing their ability to ward off disease and pests, and can limit their rate of growth.

As forest health and growth is a key component of a successful carbon sequestration project, localized atmospheric pollution may be a consideration in the siting of these projects. Trees planted should be disease and pest resistant, and appropriate to the local climate. To be effective, monitoring programs for terrestrial sequestration projects should also include parameters to evaluate general tree health and identify the presence of new or increased pest populations.

4.2.3.7.3 Forest Maintenance

To maintain forest health, prescribed burning of understory material is an accepted industry practice for mature stands. The primary purpose of prescribed burning is to reduce the hazardous accumulations of forest fuels. This aids in the prevention of wildfires, reduces the intensity of the fires, and also provides a foundation for safer, more effective fire suppression and protection operations. This burning is usually limited in scope and actively monitored by fire officials. Although prescribed burning would generate particulate matter and CO_2 on a routine basis, it would significantly reduce the chances of a larger forest fire that would not only generate more and lasting particulate pollution, but would eliminate the benefits of the forest to sequester carbon. Prescribed burning plans need to be submitted to the applicable state forest fire service for approval.

Management of smoke from prescribed burning is a critical issue. It can affect air quality, highway traffic, and nearby properties, and is subject to federal and state air pollution laws. Recent changes in the NAAQS require reduced emissions of particular matter, as well as gaseous emissions. All adjacent smoke-sensitive areas must be identified in the burning plan. Wind direction and speed, and smoke dispersal are some of the atmospheric characteristics that should be considered before conducting a burn. Firing techniques also affect smoke emissions. Hot summer burns, usually called backfires (i.e., moves in the direction of the wind), burn slowly and consume a large amount of fuel. Backfires produce considerably less emissions than other firing techniques (NJDEP, 2004). Mechanical removal of fuels may reduce emissions from controlled burning substantially. Methods of removing fuels from a forest include onsite chipping of woody material, or even allowing grazing of grassy and bushy fuels by sheep, cattle or goats.

4.2.3.8 Co-Sequestration of H_2S and CO_2

In the case of sequestering CO_2 from sour gas fields or IGCC plants, H_2S gas would also be captured and sequestered. The concentration of H_2S is assumed to be 2 percent for a typical IGCC gas stream and 25 percent on average for a typical sour gas processing plant waste gas stream.

Air impacts and permitting associated with co-sequestration of H_2S (compression and transport) would be similar to those for coal seams. The gas streams would typically contain between 2 and 25 percent H_2S, and subsequently would require pipelines and ancillary equipment to be able to withstand the corrosive properties of H_2S. Transport piping and injection wells may require additional safeguards to prevent catastrophic releases of the gas.

Gas streams that contain H_2S would generally be sequestered by injecting it into oil and gas reserves or into deep saline formations. This cost-effective method of disposal of H_2S would provide incentives for operators of IGCC and sour gas plants to sequester CO_2 that would normally be released into the atmosphere.

The impacts to air resources for co-sequestration of H_2S and CO_2 would include the minor adverse (localized) impacts associated with the release of minor amounts of criteria pollutants associated with the operation of compression and injection equipment. While it is expected that equipment and processes would meet all safety regulations to prevent the inadvertent release of gases, an inadvertent release could cause minor adverse impacts (localized and short-term), causing the release of toxic and hazardous air pollutants and causing objectionable odors. The process overall would result in a beneficial impact (long-term emissions reductions) to atmospheric resources in terms of unregulated air pollutants.

4.2.4 Mitigation of Potential Adverse Impacts

Based on possible impacts of technologies identified in Section 4.2.3, this section outlines measures recommended to mitigate potential adverse impacts of carbon sequestration projects on air quality.

4.2.4.1 Project Planning and Design

- Determine the air impacts associated with operation of CO_2 compression and injection equipment as applicable. Consult state air permitting officials to determine if the project will meet emission standards as designed.

- If the project is sponsored by the federal government and located in a non-attainment area for one or more criteria pollutant, conduct a clean air applicability analysis of the project to determine conformance to the applicable SIP.

- Locate pipelines and injection areas away from populated areas.

- For terrestrial sequestration projects, ensure local air quality will not significantly limit tree growth or health.

4.2.4.2 Construction

Before beginning a construction project, a construction permit from the state or local air permitting agency is generally required. Because most major air impacts of construction projects are local and temporary, many states do not require modeling of air quality impacts. Instead, agencies may require that certain mitigation practices are utilized, such as watering areas of soil disturbance to control fugitive dust.

Table 4-4 lists types of pollutants that can be generated during construction and site preparation activities.

Table 4-4. Pollutants and Factors Influencing Emissions from Construction of Carbon Sequestration Projects

Activity	Pollutants	Factors
Vehicular Traffic	CO, NOx, VOCs, particulates, SO_2, air toxics	Vehicle- miles traveled, travel speed
Vehicle Fugitive dust from paved and unpaved roads	Particulate	Vehicle-miles traveled, road conditions (e.g., silt loading, silt content, moisture content, vehicle weight)
Construction fugitive dust from earthmoving activities	Particulate	Acres disturbed
Construction equipment exhaust	CO, NOx, VOCs, particulates, SO_2, air toxics	Volume of fuel used
Emergency or permanent[1] generators	CO, NOx, VOCs, particulates, SO_2, air toxics	Volume of fuel used or hours of operation

[1] (Definition of emergency and permanent use of generators may vary according to state air rules)
Source: DOE, 2004.

The following BMPs can be employed to mitigate air emissions associated with construction activities.

- Dust abatement techniques should be used on unpaved, unvegetated surfaces to reduce airborne dust.
- Unpaved access roads should be surfaced with stone whenever appropriate.
- Construction materials and stockpiled soils should be covered to reduce fugitive dust.
- Disturbed areas should be minimized.
- Land should be watered prior to disturbance (excavation, grading, backfilling, or compacting).
- Disturbed areas should be revegetated as soon as possible after disturbance.
- Soil should be moist while being loaded into dump trucks.
- Dump trucks should be covered before traveling on public roads.
- Use of diesel or gasoline generators for operating construction equipment should be minimized.

4.2.4.3 Operation

The operation of carbon sequestration technologies may include the use of generators for compression and transport of CO_2 and vehicle travel that may generate fugitive dust and vehicular exhaust. Each project should evaluate where electricity lines can be run to equipment to avoid the use of internal combustion generators wherever feasible. Where utility lines are not practical, use of the BACT for compressors, pumps and heaters should be employed. The use of freight trains to transport raw materials where economically feasible may reduce air emissions associated with frequent truck traffic.

To reduce the possibility of accidental release of captured CO_2 from geologic sequestration projects, the following guidelines should be followed:

- Pressure test all pipelines and wells before placing them into service.
- Install automatic shut-off valves along pipelines and at the well-points.
- Install monitoring equipment to measure releases of CO_2 from the surface above geologic formations (MM&V).

4.2.5 Regional Considerations

Air permitting and regulations would vary depending on state requirements and the presence or absence of non-attainment areas. Geologic sequestration projects proposed in states that have non-attainment areas for CO and/or O_3 may find it difficult to permit a multitude of gas-fired compressors and pumps. These difficulties can be overcome by using equipment with BACT, extending electric utility lines to equipment and/or buying air emission credits. Construction activities for all sequestration technologies produce emissions associated with earth moving, equipment operation and vehicle traffic. However, these air impacts are usually short term and particulate matter emissions can be reduced significantly through dust-control strategies.

4.2.6 Summary of Potential Impacts

Table 4-5 provides an overall qualitative assessment of potential impacts to atmospheric resources for each sequestration technology.

All program technologies (other than terrestrial sequestration) would emit regulated pollutants on a recurring basis for the operation of compressors, pumps and heaters to transport gas streams. Assuming all project components would be properly permitted under applicable local, state and federal air emission guidelines, these emissions would pose minor to negligible impacts to air quality. These technologies are not expected to affect air quality management plans assuming that the BACT are used.

Co-sequestration projects have the potential to accidentally release varying amounts of H_2S with CO_2 to the atmosphere. Therefore, while impacts are not expected to be significant under this generally proven safe technology, there may be rare and minor (short term and localized) adverse impacts in the realm of accidental release of toxic pollutants and/or objectionable odors.

All carbon sequestration technologies are designed to remove CO_2 from the atmosphere or avoid its release into the atmosphere. Therefore all Program technologies would result in a net benefit in terms or reducing greenhouse gas emissions or atmospheric concentrations.

Table 4-5. Potential Impacts of Program Technologies on Atmospheric Resources

Impact Considerations	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Regulated air pollutants	○	○	○	○	○	○	·	○
Toxic and hazardous air pollutants	·	·	·	·	·	·	·	○
Air quality management plans	·	·	·	·	·	·	·	·
Objectionable odors	·	·	·	·	·	·	·	○
Greenhouse gases	+	+	+	+	+	+	+	+

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.3 GEOLOGIC RESOURCES

This section describes the potential impacts to geologic resources (which includes soils, geology, and groundwater) that could occur during the implementation of carbon sequestration technologies. The geologic resources that could be affected by sequestration technologies are described in Section 3.3. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.3.1 Impact Considerations

The impacts to geologic resources as a result of implementing carbon sequestration technologies would be dependent on the specific location of the proposed project. Geologic resources that could be impacted include soils, mineral resources, and groundwater sources (especially sole source aquifers, but also including all sources of drinking water).

Impacts of sequestration projects must be evaluated on a site-specific basis and would depend on a multitude of site conditions, the surrounding environment, and the technology implemented. Although the construction and site preparation could impact the geologic resources of an area, the majority of impacts would be related to the operational and post-operational periods of the project.

Potential impacts on geologic resources have been assessed using the considerations outlined below and the definitions found in Section 4.1.1. Short-term impacts for geologic resources are defined as impacts occurring for less than 1 year. Localized impacts for geologic resources are defined as those occurring within 25 miles of the project.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- cause potential for local seismic destabilization and damage to structures.
- potentially destroy high-value mineral resources or unique geologic formations, or render them inaccessible.
- cause excessive soil erosion that cannot be mitigated in site planning and design.
- require the conversion of active prime or unique farmlands to nonagricultural use.
- degrade or adversely alter the quantity or quality of groundwater within a sole source aquifer.
- deplete groundwater supplies or interference with groundwater recharge affecting available capacity of a public water source.
- conflict with established water rights or regulations protecting groundwater for future beneficial uses.
- contaminate a public water supply aquifer, causing violations of water quality criteria or standards established in accordance with the Safe Drinking Water Act, state regulations, or permits.
- conflict with aquifer management plans or goals of governmental water authorities.

4.3.2 Regulatory Framework

Carbon sequestration projects must comply with applicable Federal, State, and local laws and regulations concerned with geologic resources. The principal federal laws and regulations pertaining to these resources are listed in Table 4-6.

Table 4-6. Major Federal Laws and Regulatory Requirements for Geologic Resources

Law/Regulation	Key Elements
Safe Drinking Water Act of 1974 (42 USC § 300(f))	The SDWA specified a system for the protection of drinking water supplies, including underground sources of drinking water, through the establishment of contaminant limitations and enforcement procedures. Part C of the Act established the UIC Program to provide safeguards so that injection wells do not endanger current and future USDW.
40 CFR 144 - 149, Underground Injection Control Program.	The regulations establish minimum requirements for UIC programs, technical criteria and standards, and the construction, operation, monitoring, and reporting requirements of the program. Wells used to inject fluids for enhanced recovery of oil or natural gas are regulated as Class II wells under the program.
Soil Conservation and Domestic Allotment Act (16 USC § 5901)	This Act authorized the Secretary of Agriculture to conduct soil erosion surveys and prevention measures, and it established the Natural Resources Conservation Service to conduct these activities. Emphasis was given to engineering operations, methods of cultivation, growing of vegetation and other land uses as preventative measures.
Farmland Protection Policy Act of 1981 (7 USC § 4201)	The FPPA is intended to minimize the impact Federal programs have on the unnecessary and irreversible conversion of farmland to nonagricultural uses. It assures that—to the extent possible—Federal programs are administered to be compatible with state, local units of government, and private programs and policies to protect farmland.

4.3.3 Generalized Siting and Operational Impacts of Technologies

This section discusses the potential impacts to geologic resources based on the description of the various capture, transportation, and sequestration technologies in Section 2.5 and the geologic resources in Section 3.3. When applicable, monitoring, mitigation and verification (MM&V) methods are described with regard to mitigating or avoiding potential impacts. Employing BMPs (e.g., such as those described in the "GEO-SEQ Best Practices Manual" dated September 30, 2004 and the "Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin" prepared by ALI Consulting dated April 2002) during all phases of a geologic sequestration project would help protect the groundwater resources of the project area. These BMPs focus on eliminating the potential for leakage and contamination of the surrounding environment, and include proper injection well design with safety features (e.g., similar to a Class I or Class II injection well).

4.3.3.1 Post-combustion Capture

Post-combustion CO_2 capture technologies are expected to be retro-fitted to existing facilities or included in new facilities where the CO_2 is formed as a product of the combustion of fossil fuel. The construction of the capture facility, including the addition of access roads, would necessitate the clearing of native ground cover and grading of the land surface. These actions could increase the potential for soil erosion at the site; however, significant soil erosion and sedimentation of surface waters can be mitigated through the use of BMPs for erosion control. As the capture facility would be co-located with an existing or proposed new plant, soil resources (e.g., farmland) would only be impacted to the extent that the existing plant were to be expanded, or as an incremental impact resulting from new plant construction, which is anticipated to be insignificant.

Waste products from the post-combustion capture process could include heat-stable amine salts and other degradation products, which would be transported to the wastewater tank at the facility for off-site disposal. Spent carbon from the amine filter beds would require transport to and disposal in an appropriately permitted waste management facility. It is anticipated that waste from the oil and grease used for maintenance at the facility would not significantly add to the quantity already generated at the plant. These waste products would not impact the surface soils or groundwater quality unless an accidental spill occurs.

The capture technology requires cooling water to wash the flue gas as it exits the absorber (see model project description in Section 2.5). It has been assumed that cooling water would be supplied from the cooling water recirculation system of the existing or proposed new fossil fueled plant. Although cooling water is re-circulated in the process, losses to the system would require potentially millions of gallons of additional water per year. This water would be obtained locally, either from aquifers or existing surface water reservoirs, and proper permits would be required for these water withdrawals. The permitting processes for water resources usage include mechanisms for protecting existing water rights and local groundwater users. Also, the effect of the increased need for water on surrounding communities and users would be evaluated during the permitting process and site-specific NEPA review.

As cooling water is re-circulated, it becomes saline and may contain elevated levels of biocides, such as bromide, due to evaporation during the blow-down process. Typically, saline water is removed from the cooling water system of a fossil-fueled plant and managed in a lined reservoir (or an above-ground tank) specifically designed to prevent seepage to underlying soil and groundwater resources.

4.3.3.2 CO_2 Compression and Transport

Compression facilities are expected to be co-located with an existing power plant facility or comparable facility where the CO_2 is captured. Transport of the CO_2 from the capture location to the sequestration site can be accomplished using one of two methods, tank truck or pipeline, as described in Section 2.5.

Compression facilities and equipment for CO_2 pipelines would require land to be cleared of vegetation and potentially graded to accommodate the facilities necessary. These activities could increase soil erosion in the affected area, but appropriate use of BMPs would minimize impacts. Additionally, access roads would be created for pipeline maintenance. The pipeline corridor must remain clear of vegetation growth, other than groundcover, for pipeline access. Significant soil erosion and sedimentation of surface waters can be mitigated through the use of BMPs for erosion control.

Maintenance of transmission equipment would require use of lubricating oil. Spent lubricating oil could be stored in a waste oil tank for periodic off-site disposal in an appropriately permitted waste management facility. Under proper handling, this waste product would not impact geologic resources at the site except in the event of an accidental spill. Potential wastes from the transportation of CO_2 via a pipeline include the condensate from the compressed gas stream, which could be transferred to a wastewater tank for off-site disposal.

Compression and transportation activities would not affect the potential for geologic hazards. Valuable mineral deposits and soil resources (e.g., prime farmland) would not be significantly affected by these activities as these resources would be protected by existing mineral rights and soil conservation programs. It is also assumed that any increase in oil and grease waste would not add a significant amount to the current waste from the source facility. The waste products from the compression and transportation of CO_2 via either pipeline or tank truck would not impact the geologic resources of an area except in the event of an accidental release.

4.3.3.3 Sequestration in Coal Seams

Sequestration of CO_2 in unmineable coal seams, principally involving ECBM recovery projects, would require detailed planning to avoid or mitigate impacts to the geologic resources of an area. A detailed evaluation to address the following topics would be a prerequisite for selecting an appropriate site.

- The construction of sequestration facilities at the injection site, including excavation for foundations, may cause new or renewed movement on landslide-prone slopes in the area. These areas would be mapped and avoided during the construction phase of the project. Although the buildup and sudden release of pressure in the injection zone could theoretically induce a seismic response in the subsurface near the injection site, federal regulations and state permitting processes for injection wells include provisions to control the injection pressures, thereby minimizing this potential hazard.

- The sequestration of CO_2 in a coal seam would preclude the mining of that coal seam in the future, as the CO_2 would be released during the mining process. Therefore, to avoid the loss of a valuable mineral resource, the coal seam must be determined to be unmineable before initiation of sequestration. Sequestration associated with ECBM production, which is the most economically feasible method currently envisioned, would have a net beneficial impact on mineral resource recovery. Other nonrenewable resources that could be impacted during the sequestration of CO_2 in coal seams include groundwater quantity and quality (e.g., impacts to a water supply aquifer or geothermal springs) and mineable surface resources (e.g., sand, gravel, or aggregate deposits). Naturally occurring outcrops and surface deposits could be altered due to excavation during construction of the sequestration facilities.

- Potentially hundreds of acres of land would be required to install the required wells and equipment (see Section 2.5). Much of the land associated with the sequestration process, however, would remain in the original, natural state. Surface preparation for drill rigs and equipment, access roads, pipelines, and related facilities would require clearing of the native vegetation and potential grading of the land surface, which could increase soil erosion. The increase in soil erosion could also increase the amount of sediment in nearby water bodies. Significant soil erosion and sedimentation of surface waters can be mitigated through the use of BMPs for erosion control. With proper planning, disturbance or loss of soil resources (e.g., farmland) would be minimized.

- Useable groundwater along the outcrop of the coal seam could be affected as water levels are lowered due to pumping at the injection site. Prior to selecting an injection site, evaluations would be performed to ensure that the shallower, usable aquifers are hydrogeologically isolated from the production and sequestration zones. If the injection reservoir is not completely sealed by very low permeable formations overlying it, leakage or migration of the sequestered CO_2 could impact the groundwater quality in the area. For instance, the addition of CO_2 to the coal water-bearing formation can decrease the water pH and alter the oxidation potential (Eh) of the water causing the mobilization of trace elements (e.g., arsenic, selenium, lead).

- For projects involving methane recovery, the produced water may be of poor quality (e.g., elevated total dissolved solids and inorganic or organic parameters) and would be disposed of properly to avoid contamination of useable water sources. BMPs and facilities that are properly constructed and operated would preserve both the quality and quantity of groundwater in the area of the sequestration process.

4.3.3.4 Sequestration in Depleted Oil and Gas Reserves

Impacts to geologic resources associated with applying EOR for the sequestration of CO_2 would be similar to those described above for coal seam sequestration. However, the mere presence of petroleum is clear evidence of long-term hydrogeologic isolation of fluids within this type of subsurface reservoir. Many of the technologies that would be utilized for this sequestration process are currently in use by oil and gas production companies. Therefore, the implementation of the sequestration method is well documented and potential problems that could arise from the continued use of these technologies being investigated. With proper planning and the use BMPs, many of the impacts can be mitigated or avoided. The impact criteria with respect to the sequestration of CO_2 for EOR are discussed below.

- Damage to sequestration facility structures due to geologic hazards induced by sequestration processes can be avoided. The geologic setting and petrophysical characteristics of the oil and gas reservoir would be well studied as part of the previous planning process for the development of the petroleum resource. These details would enable proper design of sequestration facilities to avoid the potential for landslides, seismic activity, or other localized hazards.

- The sequestration process may have a favorable effect on the development of oil and gas reservoirs in the area of the injection sites. Producing oil and gas from adjoining or nearby reservoirs could stimulate the migration of sequestered CO_2 toward the petroleum extraction points, which may have a net beneficial effect, because it would increase petroleum reservoir pressures and recovery. However, without proper project planning, the sequestration process could impact other non-renewable resources, such as groundwater and mineable surface resources. In some cases, underground mines in the area of the injection site could affect the integrity of the natural, geologic seals of the reservoir.

- The land area necessary for the sequestration of CO_2 in oil and gas reservoirs depends on the number of injection wells planned and the distance between the wells. In the areas of roads, facilities, and drill pads, the land surface would need to be cleared and potentially graded. These estimates of area disturbed do not include major pipelines that may be installed to transport CO_2 to the site. Pipelines would be buried to avoid temperature fluctuations due to weather conditions. Clearing of the natural vegetation for these purposes could increase the amount and rate of soil erosion. Significant soil erosion and sedimentation of surface waters can be mitigated through the use of BMPs for erosion control. The project site would be located and operated to minimize impacts to valuable soil resources (e.g., prime farmland); however, many producing oil and gas fields are already located within or near farmland. The small incremental increase in disturbed land should not restrict the location of an EOR-sequestration site.

- In existing oil and gas fields, there are many exploration and production wells, some operating wells and some shut-in or abandoned wells. Prior to the initiation of CO_2 injection for sequestration and EOR, all such wells in the vicinity would be evaluated for proper completion to protect potable groundwater resources. Casing and annular seal integrity are particularly important. If the casing is damaged or severely corroded, or if the annulus between the casing and the drill hole is not effectively sealed with cement bentonite grout, the well may leak formation fluids. Impacts to local groundwater systems could occur as contaminants (e.g., formation fluid, CO_2, poor quality groundwater) migrate from the injection zone through the poorly completed or damaged wells in the field. Properly sealing such wells prior to CO_2 injection would preclude this contaminant migration mechanism.

- Produced fluid (i.e., non-potable water that is separated from the recovered oil as part of the EOR process) can be disposed of on-site in a properly designed, constructed, and permitted waste disposal well. The injection of CO_2 or produced water at excessive pressure may cause hydrofracturing, allowing the CO_2 to escape the naturally formed petroleum trap. The addition of CO_2 to the water-bearing oil reservoir can decrease the water pH and alter the Eh of the water, which are key factors in the solubility and mobility of trace elements (e.g., arsenic, selenium, lead). If fluids escape from the petroleum reservoir, the impacts to water quality in the shallow aquifers would depend on the quality and rate of leakage from the reservoir, and geochemical reactions between the rocks and groundwater along the migration paths. The proper design, construction and operation of facilities and implementation of BMPs would protect both the quality and quantity of groundwater in the area of the sequestration process.

4.3.3.5 Sequestration in Saline Formations

Utilizing saline water-bearing formations for the sequestration of CO_2 involves many technologies that are currently in use in several carbon sequestration sites worldwide. Thus, the equipment, processes, and potential impacts of CO_2 injection are currently being studied and evaluated. Proper planning and BMPs can help avoid or mitigate potential impacts to the geologic resources of an area due to the sequestration process. The impact criteria with respect to the sequestration of CO_2 in saline formations are discussed below.

- The potential for induced seismic responses due to the injection of CO_2 into the subsurface is low if proper injection pressures are maintained. State and federal agencies regulate the injection pressures that can be utilized during the sequestration process, and monitoring of the formation pressure would help detect potential over-pressurization. Some saline formations are located in geologic traps that also serve as petroleum reservoirs. Therefore, prior to the sequestration of CO_2 in a saline formation, the surrounding area would be studied to determine if the sequestration would affect any oil and gas resources. As with the other geologic sequestration technologies, surface and underground mining in the area of the injected CO_2 could affect the integrity of the hydrogeologic features that cap and isolate the reservoir, thus may allow undesirable migration of the CO_2.

- Land would need to be cleared for wells and equipment. Disturbances of the natural vegetation could cause increased soil erosion, but applying BMPs for protection of soils can minimize these impacts. Effective project siting and planning would avoid areas where soils are used as a resource (e.g., prime farmland). If farmland were proximal to the project site, erosion-control and groundwater-protection measures would be incorporated in the project design.

- It is essential to protect the water supply aquifers that are stratigraphically above the injection zone. The addition of CO_2 to the saline water-bearing formation can decrease the water pH and alter the Eh of the water causing the mobilization of trace elements (e.g., arsenic, selenium, lead). However, selecting sites with competent, extremely tight caprock above the injection zone and other favorable geologic features that restrict both vertical and lateral flow would isolate the sequestered CO_2 from any aquifer that could be used as a potable water supply source. Utilizing BMPs for design, construction, operation, and monitoring can control the subsurface leakage of formation fluids. Injection pressures would be carefully monitored and controlled to avoid hydrofracturing of the formation or caprock that could allow formation fluids to migrate to shallower aquifers.

4.3.3.6 Sequestration in Basalt Formations

Sequestration of CO_2 in basalt formations has not been tested in pilot-scale field projects. Therefore, much of the data needed for the successful design of a basalt sequestration program are not available, including injectivity, storage capacity, and rate of conversion (NETL, 2004). Nonetheless, it is reasonable to assume that the technologies currently available and in use for other sequestration projects would be utilized for CO_2 sequestration in basalt formations. For example, the equipment used for sequestration in saline water-bearing formations would be similar to that employed for sequestration in basalt. The differences, however, are the response of the natural system to the injected CO_2 and the potential impacts to the surrounding environment. These responses can only be ascertained following site-specific studies of CO_2 injection into basalt formations.

Proper planning and BMPs can help mitigate or avoid potential impacts to the geologic resources of an area due to the sequestration process.

- The potential for inducing seismic disturbances by injection of CO_2 into basalt formations is low if proper injection pressures are maintained and a complete and thorough site investigation is conducted prior to project initiation. Additionally, monitoring formation pressures in the sequestration zone and surrounding formations will help identify any potential over-pressurization that could generate a seismic response.
- The location of any basalt sequestration project should be investigated to determine if any valuable mineral deposits could be adversely affected. With proper planning and design of the sequestration project, valuable mineral deposits can be protected.
- Land would need to be cleared for wells and equipment. Disturbances of the natural vegetation could cause increased soil erosion; however, applying BMPs for protection of soils can minimize these impacts. Proper project siting and planning would avoid areas where soils are being used as a resource (e.g. valuable farmland), if negative impacts were predicted. Farmland or other natural resources surrounding a project site would be protected through use of erosion-control, spill prevention and groundwater-protection measures.
- A competent, extremely tight caprock and geologic features that trap the injected CO_2 in the basalt formation are essential to protect water supply aquifers located stratigraphically above the injection formation. Injection pressures would be monitored and controlled to avoid excessive pressures that could breach the integrity of the low permeability formations above the injection formation. This monitoring, along with implementing BMPs and the other proper MM&V protocols, should protect the groundwater availability, use, and quality above the target injection formation.
- Based on initial studies, the Big Sky Regional Carbon Sequestration Partnership (BSRCSP) expects favorable geochemical reactions to occur between the basalt and the injected CO_2 (BSRCSP, 2005). While such geochemical reactions may further reduce the potential for impacts of CO_2 injection on overlying groundwater aquifers, the *in-situ* kinetics of these geochemical reactions are not yet clearly established, but may require a period of several hundred years to reach the reaction end points (BSRCSP, 2005). Moreover, the available data are insufficient to evaluate the degree to which these reactions may create adverse plugging effects in the fractured basalt reservoir due to precipitation of clay minerals.

4.3.3.7 Terrestrial Sequestration – Reforestation

Forests provide natural carbon sinks, and utilizing this natural process by implementing a reforestation program on mined lands, as described in the model project presented in Section 3, provides an additional option to geologic sequestration of CO_2. Currently, many mined lands are reclaimed as grasslands rather than reforested. The capacity of grasslands to sequester CO_2 is lower than the demonstrated capacity of forestland. The site climate and other environmental conditions must be evaluated prior to the initiation of a reforestation project, and it may take as many as 20 to 70 years for the forest biomass to be adequate to reach peak sequestration rates, depending on the management practices, species of trees utilized, and environmental setting. The impact criteria with respect to the sequestration of CO_2 utilizing the natural processes associated with reforestation are discussed below.

- The reforestation process would not increase the potential for geologic hazards in the area of a terrestrial sequestration project. Reforestation may in fact have a net beneficial effect on soil structure and land stability. Since reforestation would initially be implemented on abandoned and reclaimed mine lands, mineral and energy resources would not be impacted adversely. Soil amendments and erosion control measures implemented as part of the reforestation project could beneficially affect surrounding active farmland. Any pesticides or herbicides used in the project to control weeds and other competition to the newly planted trees could percolate into the shallow groundwater or runoff to surface water bodies if not properly applied. However, the establishment of newly forested areas on lands damaged by prior mining activities would likely have a net beneficial impact on groundwater resources.

- The improvement of damaged soils is a key element for successful reforestation of mined lands, and the productivity of the terrestrial ecosystem can be enhanced through the application of soil amendments (e.g., coal combustion byproducts and bio-solids from wastewater treatment facilities). The reforestation process is a natural combatant to soil erosion. If the reforestation plan includes harvesting the trees, there is a potential for sediment and erosion issues during the harvesting stage. Without proper management, the harvesting and re-planting process could introduce various wastes into the soils and shallow groundwater (e.g., fuel spills and oil and grease from harvesting and planting equipment).

4.3.3.8 Co-Sequestration of H_2S and CO_2

The impact criteria with respect to the co-sequestration of H_2S and CO_2 are discussed below.

- Impacts on geologic resources associated with the co-sequestration of CO_2 with H_2S from sour gas fields or IGCC plants generally would be similar to those described for geologic sequestration in oil and gas reserves or saline formations. Adding H_2S to the CO_2 injection stream has the potential to exacerbate the magnitude of the impacts described above for injecting CO_2 alone. For example, H_2S is a strong corrosive agent, so it is likely to cause an increase risk of well casing leaks. In the event of casing leakage into a shallow potable aquifer, the H_2S would create more acidic groundwater and thus have the potential to mobilize higher concentrations of trace metals in the aquifer. Nonetheless, as with the cases for pure CO_2 injection, proper planning and implementation of BMPs can help avoid or mitigate potential impacts to the geologic resources of an area due to the sequestration process.

- The combination of H_2S with injected CO_2 would increase the potential for contamination of useable groundwater, therefore, the protection of water supply aquifers in the vicinity of the injection zone would be a foremost priority. A competent low-permeability caprock and geologic features that restrict vertical flow, which are typical characteristics of natural subsurface petroleum reservoirs, would isolate the sequestered CO_2 and H_2S from any aquifer that could be used as a source of potable water. Also, the addition of CO_2 and H_2S to a saline water-bearing formation can decrease the water pH and alter the Eh of the water causing the mobilization of trace elements (e.g., arsenic, selenium, lead). However, the subsurface leakage of formation fluids can be controlled by utilizing BMPs for design, construction, operation, and monitoring. Injection pressures would be carefully monitored and controlled to avoid hydrofracturing of the formation or caprock that could allow formation fluids to migrate to shallower aquifers.

4.3.4 Mitigation of Potential Adverse Impacts

The measures discussed in the following section are recommended to mitigate potential adverse impacts of CO_2 sequestration technologies on the geologic resources of an area. Significant impacts can be avoided by using a rigorous site evaluation process to select CO_2 injection sites having favorable hydrogeologic characteristics for the long-term isolation of CO_2 and formation fluids. Additionally, BMPs employed during all phases of the project would help protect the resources of the project area. A well-designed contingency plan is essential to minimize any potential impacts to the geologic resources of an area. Various measures that should be employed to protect the geologic resources of a project area are discussed below.

4.3.4.1 Project Planning and Design

Effective site selection is a critical requirement for a successful carbon sequestration project. The planning and design phase of any project is pivotal to the protection of the surrounding geologic resources. Detailed site selection studies and subsurface investigations would be required for collecting site-specific hydrogeologic data to determine the hydraulic characteristics of the injection zone and overlying confining units (e.g., exploratory drilling, groundwater quality sampling, hydraulic testing, and geologic testing). In addition, groundwater flow and transport modeling is a well-established technical basis for predicting the future hydraulic responses of injection and the potential effects of fluid migration. Additionally, baseline levels should be established for a variety of environmental parameters that may be used to detect effects of the sequestration (e.g., water quality analyses, bradenhead tests, soil vapor analyses). As part of project planning, a monitoring program should be developed that includes monitoring surrounding wells and other potential points of migration into the biosphere. Both the monitoring frequency and the constituents to be analyzed should be specified. A spill prevention and contingency plan is also a fundamental component of the planning and design phase of a project. This plan should include the steps necessary to avoid potential impacts to the surrounding geologic environment.

> Detailed site selection studies and subsurface investigations would be required to determine the hydraulic characteristics of the injection zone and overlying confining units.

> *Bradenhead testing* - The bradenhead is the portion of the wellhead that is in communication with the annular volume between the surface casing and the next smaller casing string. Conceptually, if there is positive pressure at the bradenhead, this indicates that a casing leak or an inadequate cement job could exist on a well.

The monitoring plan should include:

- Measure water levels, pressures, temperatures, and water chemistry parameters in aquifer monitor wells surrounding the injection wells at specified intervals prior to, during, and following injection of CO_2.

- Monitor water chemistry at base of slightly-saline groundwater zone for early detection of potential upward leakage.
- Conduct mechanical integrity tests (e.g., bradenhead tests) at project injection wells and other surrounding petroleum extraction wells.
- Install additional monitor wells, as necessary, to provide a means of early detection of potential migration of the injected CO_2 both vertically and laterally, and to thus protect water supply aquifers.
- Inventory and monitor springs, seeps, wetlands, and surface water bodies (especially along the outcrop of a coal seam utilized in an ECBM-sequestration project).
- Utilize thermal infrared and near-infrared aerial photos over time to document the pre-injection, injection, and post-injection vegetation and surface water conditions in the site area.

The spill prevention and contingency plan should include:

- Shut down the project injection wells if undesirable leakage, seepage, or other problems are detected.
- If a problem is detected, increase monitoring scope to evaluate the nature and extent of impact.
- Implement a corrective action to control the rate of degradation and migration (e.g., pumping at lower pressure, extract and re-inject water) if the water chemistry parameters measured in the monitored groundwater or wells exceeds drinking water standards or other cleanup goals.

Hydrogeologic investigations, including aquifer testing and hydrostratigraphic logging, followed by numerical flow and transport modeling, would help in project planning and monitoring plan development and thus aid in preventing adverse impacts to water supply aquifers in the project area. Additionally, a survey of the surrounding water wells should be included in the planning phase of the project. Hydrogeologic characteristics and project design features that would mitigate potential negative effects of the sequestration process include:

- Competent, extremely tight caprock overlying the injection reservoir – for example, a thick and laterally-continuous shale unit.
- Marginal- to poor-quality overlying aquifers are not used as water supplies.
- Minimize injection pressure to not exceed the hydraulic pressure needed for fracture initiation (also known as the critical pressure or breakdown pressure).
- Remediate any old or poorly-completed wells prior to injection.
- Avoid any area containing a “sole source aquifer” as designated by the EPA.

> To avoid potentially significant adverse impacts, geologic sequestration injection areas should not be sited near sole-source aquifers (as designated by EPA).

In order to protect the soils in the project area, the design for the site should minimize land disturbance, including the clearing of native vegetation for development of access roads or the creation of new pipeline corridors. Reclaimed land is only an approximation of the natural system as the *in-situ* materials are replaced with fill materials. Consequently, the soil productivity in reclaimed land areas requires extensive time to recover. However, to aid in the recovery process, topsoil removed during the construction phase should used for rehabilitation. Extensive soil erosion controls should be added to the project design to decrease the potential for soil loss and sedimentation in nearby surface water bodies.

The sequestration project should be designed to avoid mineable resources (e.g., mineral deposits, petroleum reservoirs, coal seams, and surface sand, gravel, or aggregate deposits) and valuable soil resources (e.g., fertile, high quality farmland). The CO_2 injection pressure should be designed to not exceed the fracture initiation pressure in the target formation. This would help preserve the natural, geologic trap for the sequestered CO_2 as well as prevent hydrofracturing and potential associated geologic hazards. Injecting CO_2 into sufficiently porous and permeable rock would help avoid this excessive buildup of pressure, and the target formation should be tested for these hydrogeologic characteristics during the project design.

Other geologic hazards, such as landslide-prone areas and areas of instability, can be avoided through the proper geotechnical testing and design. Situating the project on the site in areas of low topographic relief would help minimize disturbances and avoid such hazards. Geotechnical engineering measures (e.g., subsurface drainage, retaining walls, and soil reinforcement) can also help to avoid an impact to both the natural environment and the project facilities.

> For geologic sequestration, it is essential to select sites with favorable hydrogeologic conditions for isolating the CO_2 from groundwater resources, especially sole source aquifers. Areas with known geologic hazards (including earthquakes and landslides) should also be avoided.

4.3.4.2 Construction

In general, the design and planning phase of the sequestration project should provide for the construction measures needed to protect the geologic resources in the project area. The use of BMPs during construction would help eliminate any unforeseen impacts due to the execution of the sequestration technology. Several actions that can be incorporated into the construction planning include the following.

- Minimize the footprint of the facilities and disturbed land thereby maintaining the native vegetation and decreasing the potential for erosion.
- Use effective soil erosion control measures.
- Use topsoil that is removed and stockpiled during construction for re-vegetation to stabilize restored areas during reclamation process.
- Proper injection well design is essential to minimize potential impacts to the local groundwater system. All wells must be properly completed utilizing materials to minimize corrosion (acidic-saline water created), and wells should be properly developed and tested.
- Mechanical integrity tests (e.g., bradenhead tests) should be performed on all new and existing wells.
- Any poorly completed wells should be remediated prior to the initiation of CO_2 injection.

4.3.4.3 Operation

As with the construction phase of the sequestration project, the measures taken to avoid impacts to the geologic resources of the site during operation should be accounted for in the planning and design of the project. BMPs should be followed during the operation of the sequestration technology to avoid any unforeseen adverse impacts to the surrounding environment. Monitoring and contingency plans should be included as part of the project planning phase, and must be implemented during the realization of the technology. Various measures can be incorporated in the operation of the sequestration project to protect the resources in the surrounding area, as described below.

- Minimize the increase in injection target formation pressures to minimize the potential for hydrofracturing, which could allow CO_2 migration out of the target formation at a point of weakness (e.g., fault, fracture, annulus of poorly-completed well).
- Implement groundwater monitoring plan.
- Implement contingency plan, if required.
- Replace any wells impacted by the sequestration technology.

Several MM&V technologies, such as geophysical techniques (including surface and borehole seismic, electromagnetic, gravity, and other methods) and injected tracers, can be utilized during the site selection and detailed site hydrogeologic characterization to establish baseline values. These baseline data could be compared to future detection monitoring data to evaluate potential leaks and impacts.

- Seismic tomography and monitoring
- Wireline geophysical logging
- Measurement of *in-situ* temperatures and pressures
- Electromagnetic imaging
- Injected tracers to track migration of CO_2

4.3.5 Regional Considerations

Potential impacts to the geologic resources of an area would vary between the states, and would be influenced by the number and size of geologic sequestration projects, and the specific geologic characteristics of the receiving formations. For each sequestration technology, there are key siting factors that should be considered, as discussed below. These factors may limit the locations that would be amenable to the implementation of the particular sequestration technology. A description of U.S. geologic resources is found in Section 3.3. For all geologic sequestration technologies, it is essential to avoid sites located in areas where sole source aquifers have been designated. Also, projects that would require significant withdrawals of groundwater for process operations may pose problems in areas where groundwater supplies are constrained and local restrictions apply. Areas of known geologic hazards (including earthquakes and landslides) should be avoided during project siting. Additionally, areas of non-renewable resources (e.g., mineral or petroleum deposits, surface deposits, or soil resources) should be carefully evaluated, avoided and protected prior to initiation of CO_2 sequestration activities at each facility.

- **Sequestration in coal seams** – Limitations for use of coal seam CO_2 sequestration relate mainly to the geologic setting of the coal deposit. For example, shallow coal seams or coal seams that outcrop near the injection locations are not suitable sites for sequestration due to increased risk of leakage to the biosphere. Additionally, competent caprocks must be present to avoid potential adverse impacts to the surrounding environment due to migration of the injected CO_2.

- **Sequestration in depleted oil and gas reservoirs** – Site condition requirements for sequestration of CO_2 in depleted oil and gas reservoirs are similar to those described above for coal seam sequestration. Site selection and characterization activities are necessary to determine whether favorable hydrogeologic conditions exist for the long-term storage of the injected CO_2.

- **Sequestration in saline water-bearing formations** – Isolation of the target injection zone from overlying water supply aquifers is essential. An adequate caprock must be present and the geologic trap should be competent to prevent vertical or lateral migration of the injected CO_2. Areas near large population centers where groundwater is a key resource are not ideal for this type of sequestration project.

- **Terrestrial Sequestration: Reforestation** – The climate and existing soils must be suitable for the implementation of a reforestation project.

4.3.6 Summary of Potential Impacts

Table 4-7 provides an overall qualitative assessment of potential impacts on geologic resources for respective sequestration technologies. In general, the impacts of potential projects on these resources would range from negligible to minor provided that site selection is performed properly and that BMPs and other mitigation protocols are implemented effectively during planning, design, construction, and operation. Under these circumstances, significant adverse impacts would not be anticipated for any proposed technologies. However, site-specific NEPA reviews would be required to ensure that locally significant resources would not be adversely affected by proposed projects.

Risk factors that could result in moderate to significant adverse impacts include:

- lack of caprock integrity;
- seismic activity;
- uplift and subsidence;
- unsealed boreholes;
- degradation of sealed boreholes (such as corrosion well materials over time or incomplete sealing);
- EOR-induced seismicity;
- fault activation;
- undetected faults, fracture networks, shear zone, etc.; and

- proximity of sole-source aquifers or other drinking water aquifers.

The unintended release of CO_2 from its destination formation into any overlying drinking water aquifer or the atmosphere could result in significant adverse impacts. Gradual releases of CO_2 to the surface or water supplies would generally not cause significant adverse impacts to humans or the environment. Conversely, rapid and large volume releases may cause significant adverse impacts to human health and the environment as discussed in Section 4.10. The impacts caused by a release of sequestered CO_2 to overlying water supplies could vary, depending on: the amount CO_2 released; any H_2S contained in the sequestered gas; the quality of the formation fluid; the lowering of pH and alteration of the redox potential (Eh) of groundwater; and the potential of the CO_2 to mobilize metals and other minerals in the aquifer.

Terrestrial sequestration projects involving the reclamation of abandoned mine lands may have net beneficial impacts on geologic resources at selected sites, including reduced landslide potential, soil stabilization and enhanced erosion control, and potential improvement in groundwater availability and quality afforded by the restoration of natural vegetation.

Coal seam sequestration with ECBM recovery and geologic sequestration with EOR would potentially have net beneficial impacts attributable to the recovery of these economically valuable mineral resources.

Table 4-7. Potential Impacts of Program Technologies on Geologic Resources

Impact Considerations	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Geologic hazards	·	·	○	○	○	○	+	·
Valuable mineral deposits	·	·	+	+	·	·	·	+
Soil erosion	·	·	·	·	·	·	+	·
Prime or unique farmland	·	○	·	·	·	·	·	·
Groundwater availability and uses[1]	·	·	○	○	○	○	+	○
Groundwater quality[1]	·	·	○	○	○	○	+	○

[1] The impacts under groundwater availability and uses and groundwater quality for geologic sequestration technologies could range from moderate to significant if a catastrophic release of CO_2 occurred where it contaminated an overlying drinking water aquifer.

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.4 SURFACE WATER RESOURCES

This section describes the potential impacts to surface water resources that could occur during the implementation of carbon sequestration technologies. The surface water resources that could be affected by sequestration technologies are described in Section 3.4. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.4.1 Impact Considerations

Surface water resources that may be affected by sequestration projects include rivers, streams, lakes, ponds, reservoirs, estuaries and oceans. Potential impacts on surface water resources have been assessed using the general criteria outlined below and the definitions found in Section 4.1.1. Short-term impacts for surface water resources are defined as impacts occurring for less than 1 year. Localized impacts for surface water resources are defined as those occurring within 1 mile of the relevant source.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- adversely affect capacity of available surface water resources.
- conflict with established water rights or regulations protecting water resources for future beneficial uses.
- contaminate public water supplies and other surface waters exceeding water quality criteria or standards established in accordance with the Clean Water Act, state regulations or permits.
- conflict with regional water quality management plans or goals.
- substantially alter storm water discharges and adversely affect drainage patterns, flooding, and/or erosion and sedimentation.
- conflict with applicable storm water management plans or ordinances.
- cause construction of facilities in or otherwise impede or redirect flows in the 100-year floodplain or other hazard areas.
- cause filling of wetlands or otherwise alter drainage patterns that would adversely affect jurisdictional wetlands.

The extent to which surface water resources that could be affected by carbon sequestration projects depend on the operational effectiveness of systems for wastewater management, spill prevention, seepage control and monitoring implemented at the project site, the proximity to surface water bodies, amount of land to be disturbed and any permitted discharges.

4.4.2 Regulatory Framework

Carbon sequestration projects would need to consider applicable federal, state, and local laws and regulations concerned with surface water resources. Major federal laws and regulations for surface water resources are listed in Table 4-8. Provisions of the Clean Water Act relevant to the Program are described in Table 4-9.

Table 4-8. Major Laws and Regulatory Requirements for Surface Water

Law/Regulation	Key Elements
Clean Water Act of 1977, as Amended (Federal Water Pollution Control Act of 1972, as Amended) (33 USC § 1251).	This Act is a compilation of decades of Federal water pollution control legislation. The Act amended the Federal Water Pollution Control Act (FWPCA) and requires Federal agency consistency with state nonpoint source pollution abatement plans. The CWA is the major Federal legislation concerning improvement of the Nation's water resources. The Act was amended in 1987 to strengthen enforcement mechanisms and to regulate stormwater runoff. The Act provides for the development of municipal and industrial wastewater treatment standards and a permitting system to control wastewater discharges to surface waters. The CWA contains specific provisions for the regulation of dredge soil disposal within navigable waters and for the placement of material into wetlands. Permits are required under sections 401, 402, and 404 for Proposed Actions that involve wastewater discharges and/or dredging/placement of fill in wetlands or navigable waters. These permits are required prior to the initiation of Proposed Actions.
Oil Pollution Act (OPA) of 1990 (Public Law 101-380, 33 USC § 2701).	This Act prohibits the harmful discharges of oil and hazardous substances into waters of the U.S. or discharges that may affect natural resources owned or managed by the U.S.. The Act amended section 311 of the CWA to augment Federal response authority, increase penalties for oil spills, expand the organizational structure of the Federal response framework, and provide an emphasis on preparedness and response activities.
Rivers and Harbors Act of 1899 (33 USC § 401).	This Act, commonly referred to as the Refuse Act, provides authority to the U.S. Army Corps of Engineers to issue or deny permits for the construction of dams, dikes, or other structures in or affecting navigable waters of the U.S..
Wild and Scenic Rivers Act 16 U.S.C. § 1271 et seq.)	The Wild and Scenic Rivers Act was enacted to preserve, in free-flowing condition, certain select rivers of the Nation which "possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values." The Act designates over 130 rivers, with adjacent land, as components of the System. Wild river areas are defined as rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watersheds or shorelines essentially primitive and waters unpolluted. These represent vestiges of primitive America. Scenic river areas are defined as rivers or sections of rivers that are free of impoundments, with shorelines or watersheds still largely primitive and shorelines largely undeveloped, but accessible in places by roads. Recreational river areas are defined as rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past.
Executive Order 11990, Protection of Wetlands (24 May 1977; 42 FR 26961)	Federal agencies must minimize the destruction, loss or degradation of wetlands.
Executive Order 11988, Floodplain Management (24 May 1977; 42 FR 26951)	Federal agencies must reduce the risk of flood loss, to minimize the impact of floods on human safety, health and welfare, and to restore and preserve the natural and beneficial values served by floodplains.

Table 4-9. Clean Water Act Provisions

Section	Description
Subchapter III - Standards and Enforcement	
Section 301 - Effluent limitations	This section prohibits the discharge of a pollutant from a point source to waters of the U.S. without a permit. A point source is any discrete conveyance (e.g., pipe, ditch, spillway, etc.). Section 301 also describes the authority that the EPA Administrator has to add or remove substances from the list of priority pollutants. It outlines a set of procedures that must be followed whenever a substance is moved on or off the list. Anyone wishing to discharge pollutants through a 'point source' must obtain a permit from EPA or an authorized state agency.

Section	Description
Section 307 - Toxic and pretreatment effluent standards	This section describes the factors that EPA must consider when setting effluent standards for toxic pollutants. It requires public consideration of those standards before they are finalized and orders all standards to be reviewed every three years. There are two types of standards for priority pollutants. One group applies to industries that discharge their effluent directly to receiving waters. The other group applies to industries that must pretreat their effluent before releasing them to public sewers. Furthermore, this section provides the authority for the Agency's overall pretreatment program, which regulates discharges from industrial users into Publicly Owned Treatment Works (POTWs).
Section 308 - Records and reports; inspections	This section gives EPA the authority to require all dischargers to maintain adequate monitoring and record-keeping reports, install equipment, sample, and provide other information at the facilities. EPA and its authorized representatives can also inspect facilities or records and monitoring stations.
Section 309 - Enforcement.	This section gives EPA the authority to seek administrative, civil, or criminal penalties and injunctive relief against violators. The Agency may issue an administrative order or initiate a civil judicial action to require a discharger to achieve compliance and seek a civil penalty; or seek criminal penalties for negligent violations, knowing violations, or false statements made in the documents required to be submitted under the Act.
Section 311 - Oil and hazardous substance liability	This section prohibits the discharge of oil or hazardous substances to navigable waters, or adjoining shorelines. This section also provides for the establishment of the National Contingency Plan for removing oil and hazardous substances. This section authorizes the federal and state governments to recover the cost of pollution control and of damages caused by violations, depositing them in the Plan's account. This section also gives EPA the authority to seek penalties for violations of Section 311. This section also establishes the Agency's authority to promulgate regulations for the Spill Prevention Control and Countermeasures (SPCC) program.
Subchapter IV - Permits and Licenses	
Section 402 - National Pollutant Discharge Elimination System (NPDES)	This section establishes the National Pollutant Discharge Elimination System permit program under which the Administrator (or an authorized state) may issue a permit to a point source for the discharge of any pollutant, or combination of pollutants. EPA published permit application requirements for Phase I stormwater sources on November 16, 1990. Under Phase I, EPA required NPDES permit coverage for stormwater discharges from: Medium and large municipal separate storm sewer systems located in incorporated places or counties with populations of 100,000 or more; Eleven categories of industrial activity which includes construction activity that disturbs five or more acres of land. Phase II became final on December 8, 1999, which requires permitting for small construction activities that result in land disturbance of equal to or greater than 1 and less than 5 acres and certain regulated small municipal separate storm sewer systems.
Section 404 - Permits for dredged or fill material	This section authorizes a special permit program to control dredge and fill operations. The Secretary of Army and the EPA Administrator are jointly responsible for setting the guidelines by which permits are to be judged. EPA controls what areas can be listed as suitable disposal sites and can prohibit certain materials from being discharged at an approved site on certain grounds. In addition, Section 10 of the Rivers and Harbors Act requires a permit from the Army's Corps of Engineers for obstructions in navigable waters.
Section 405 - Disposal or use of sewage sludge	This section authorizes the issuance of permits for the disposal of sewage sludge generated at a publicly owned treatment works (including the removal of in-place sewage sludge from one location and its deposit at another location).

Source: EPA, 2004a and 2004b.

4.4.3 Generalized Siting and Operational Impacts of Technologies

4.4.3.1 Post-combustion Capture

As described in Section 2.5, post-combustion capture projects would be retro-fitted to an existing power plant. Such projects are likely to be located in an industrial site adjacent to an existing power plant or other industrial facility. Utility hookups and access roads are expected to already exist. The construction of such a project would require amendment to the facility's Phase I NPDES.

A single commercial sized post-combustion capture project is predicted to require the delivery of thousands of gallons of aqueous solvent a day (30 percent monoethanolamine) and tons of soda ash each month (see Section 2.5). Delivery, storage and handling of these materials would require incorporating these processes into existing facility Storm Water Management and SPCC plans.

4.4.3.2 CO_2 Compression and Transport

As described for the model project in Section 2.5, two options were considered for transporting CO_2 to a sequestration site. In the first option, CO_2 from flue gas or another industrial source would be transported by compressed gas pipeline to a sequestration site. In the second, liquid CO_2 would be transported to the site via commercial refrigerated tank trucks.

Either option would require small land areas for surface facilities which would most likely be located on the property of a power plant or other industrial facility (CO_2 source). However, the use of a compressed gas pipeline would require transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements would be required. The construction of pipelines and/or support facilities would require either a Phase I or Phase II NPDES permit. Pipelines that cross water bodies may require a Section 404 permit from the Corps of Engineers.

The option of transporting CO_2 to a sequestration site via tank trucks is expected to have minimal impacts on surface water resources.

Compression of CO_2 will result in condensate water at a per project rate of approximately 25 to 346 gallons per hour for transport by pipeline (see CO_2 Transport Model Project). This condensate water may contain impurities and traces of other chemicals, such as benzene. If dissolved concentrations of trace chemicals or salinity of this water exceeds standards for discharge to surface water, the condensate water would be collected and then disposed of in compliance with applicable regulations. The typical practice for disposing of saline water containing significant dissolved petroleum constituents is to inject the wastewater into a nearby deep salt water disposal well, which is permitted under the Underground Injection Control Program.

4.4.3.3 Sequestration in Coal Seams

Site preparation activities would include road development and clearing of ground cover. The use of a compressed gas pipeline would require additional land and surface disturbance for transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements would be required. The construction of pipelines and/or support facilities would require either a Phase I or Phase II NPDES permit. Pipelines that cross water bodies may require a Section 404 permit from the Corps of Engineers, and/or a Section 10 permit from the Coast Guard.

Short-term surface water impacts during construction of the surface facilities would be minor, relating to the activities necessary to clear the site. These construction activities would comply with state or local soil conservation permit requirements and BMPs to reduce sedimentation of nearby water bodies. Introduction of large areas of impervious surfaces such as paved roads and parking lots may require stormwater retention or detention basins to be constructed.

> CBM sites can generate large quantities of water with the released CBM, which may contain elevated levels of dissolved solids and may have high salinity. Without proper treatment, discharge of poor quality water to surface water could cause degradation of the receiving water body.

Commercial sized CBM sites (with or without CO_2 injection) tend to generate large quantities of water with the CBM, which may have elevated dissolved solids and high salinity in some areas. Without proper treatment, discharge of poor quality water from CBM activities to surface water supplies could cause degradation of the receiving body of surface water. To avoid such impacts, CBM projects that produce water exceeding CWA standards or local surface water regulations typically reinject the produced water into a deep saline formation on-site. If the site does not have direct access to an injection well permitted under the UIC program, it can be trucked to a site that does have a permitted wastewater injection well. Depending on the quantity of water generated, it may be stored in lined ponds or in steel tanks until it can be transported to the deep saline well disposal site. On the other hand, if the produced water is relatively pure with low salinity, and meets CWA standards, CBM operators may apply for a permit (i.e., a NPDES or SPDES permit) to discharge this water (pre-treated if necessary) to a local water body, such as streams or rivers. Regardless of the option used for disposing of this water, any options for discharging process water to surface or groundwater would require an appropriate discharge permit and meet stringent standards in accordance with local, state and federal guidelines. These discharges would require routine monitoring and reporting.

For example, in January 2005 Powder River Gas LLC was issued a permit from the Montana Department of Environmental Quality to discharge water from CBM operations to specific outfalls on the Tongue River under permit MT0030660. Under this permit, effluent must meet specific criteria for the following parameters: pH, specific conductivity, sodium, calcium, magnesium, dissolved solids, sodium adsorption ration, total suspended solids, cadmium, selenium, arsenic, mercury and radium. In addition, for the first two years of the permit, Powder River Gas LLC must monitor 16 additional parameters, including biological oxygen demand, chemical oxygen demand, nitrite/nitrate, a large range of metals, oil and grease, and must also perform quarterly biologic toxicity testing (Montana DEQ, 2004).

Although the carbon sequestration program does not directly result in the water discharges from CBM production, the ability to enhance CBM production through CO_2 injection may increase the lifespan of existing CBM facilities and cause new CBM facilities to be constructed. Therefore, the carbon sequestration program may cause an increase of associated discharges to surface water bodies.

Long-term surface water impacts from operations would be negligible to moderate depending upon the location of surface facilities. Impacts associated with wastewater from compressing CO_2 and recovery of CBM could be mitigated with proper collection, treatment, monitoring and disposal methods.

4.4.3.4 Sequestration in Depleted Oil and Gas Reserves

As described in Section 2.5, there are many existing commercial-sized projects where CO_2 is injected into oil reservoirs as part of EOR from which the following information is based. Siting for these projects would depend on the identification of suitable, existing oil reservoirs within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance.

Site preparation activities would include road development and clearing of ground cover. The use of a compressed gas pipeline would require additional land and surface disturbance for transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements or rights-of-way would be required.

Short-term aesthetic impacts during construction of the surface facilities would be minor, relating to the activities necessary to clear the site. These construction activities would comply with state or local soil conservation permit requirements and BMPs to reduce sedimentation of nearby water bodies. Introduction of large areas of impervious surfaces such as paved roads and parking lots may require stormwater retention or detention basins to be constructed. Wells used for CO_2 injection should be cased and cemented to prevent leakage into freshwater sources.

Like the CBM process, EOR operations would generate wastewater when separating CO_2 and water from the recovered oil. Similarly, wastewater from EOR operations is typically reinjected into a UIC-permitted saltwater disposal well. If such a well is located off-site, the wastewater would be stored in lined ponds or steel tanks until it can be economically trucked to appropriate disposal site. Storage of wastewater in lined ponds would require an appropriate permit and compliance with any associated monitoring and reporting requirements. If the wastewater has acceptable quality for discharge to surface water, a NPDES permit would be required prior to such a discharge.

Like the CBM process, EOR operations typically reinject wastewater into UIC-permitted saltwater disposal wells.

Long-term surface water impacts from operations would be negligible to moderate depending upon the location of surface facilities. Impacts associated with wastewater from compressing CO_2 and recovery of oil could be mitigated with proper collection, treatment, monitoring and disposal methods.

4.4.3.5 Sequestration in Saline Formations

Siting for carbon sequestration projects in saline formations would depend on the identification of suitable formations within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance. Therefore, saline formations located near existing fossil fuel-fired power plants or other CO_2 sources would be optimal candidates for commercial application initially.

Site preparation activities would include road development and clearing of ground cover. Wells used for injection should be cased and cemented to prevent leakage into freshwater sources. However, the use of a compressed gas pipeline would require transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements would be required.

Short-term surface water impacts during construction of the surface facilities would be negligible, relating to the activities necessary to clear the site. These construction activities would comply with state or local soil conservation permit requirements and BMPs to reduce sedimentation of nearby water bodies. Introduction of large areas of impervious surfaces such as paved roads and parking lots may require stormwater retention or detention basins to be constructed. Long-term surface water impacts from operations would be negligible, as the process would not generate wastewater requiring surface discharge. As injection of CO_2 would occur in deep saline formations that would undergo thorough geologic characterization, breakthrough of CO_2 to the surface and to surface water bodies is very unlikely.

4.4.3.6 Sequestration in Basalt Formations

Siting for carbon sequestration projects in basalt formations would depend on the identification of suitable formations within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance. Therefore, basalt formations located near existing fossil fuel-fired power plants or other CO_2 sources would be optimal candidates for commercial application initially.

Land would be required for surface facilities. The use of a compressed gas pipeline may require additional land for transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements would be required. Site preparation activities would include road development and clearing of ground cover. The construction of pipelines and/or support facilities would require either a Phase I or Phase II NPDES permit. Pipelines that cross water bodies may require a Section 404 permit from the Corps of Engineers, and/or a Section 10 permit from the Coast Guard.

Short-term surface water impacts during construction of the surface facilities would be negligible, relating to the activities necessary to clear the site. These construction activities would comply with state or local soil conservation permit requirements and BMPs to reduce sedimentation of nearby water bodies. Introduction of large areas of impervious surfaces such as paved roads and parking lots may require stormwater retention or detention basins to be constructed.

As injection of CO_2 would occur in deep basalt formation, where the CO_2 is expected to undergo mineralization over time, breakthrough of CO_2 to the surface and to surface water bodies is very unlikely.

4.4.3.7 Terrestrial Sequestration - Reforestation

The enhancement of terrestrial carbon sequestration through reforestation projects involving landscapes that have been degraded from the extraction of fossil fuels would have a net beneficial impact on surface water resources. The planting of trees in these areas would not only provide the potential for removing CO_2 from the atmosphere, but reforestation would reduce soil erosion and water body sedimentation. Trees help reduce stormwater runoff by intercepting rainwater on its leaves, branches and trunk, where it evaporates, or slowly soaks into the ground, reducing peak flow after a storm. Trees also reduce the volume of runoff.

It has been suggested that the afforestation of grasslands, shrublands, and croplands could have some negative impacts on surface and groundwater. Trees have far greater water demands than smaller woody or herbaceous plants, thus, the streamflows of nearby streams and rivers could be reduced as a result of afforestation efforts. Also, trees have greater nutrient demands than other, smaller plant species and afforestation projects could lead to reduced nutrient levels and increased salinities of soil (Jackson et al., 2005). The focus of terrestrial sequestration efforts is to reforest barren, formerly mined lands, not to alter areas that are currently farmed or contain natural, undisturbed vegetation. Therefore, it is assumed that the benefits of reforestation projects outweigh the potential negative effects to surface and ground water and soil geochemistry. However, the potential for these negative impacts to occur should be considered during the planning of terrestrial sequestration projects.

> Acid Mine Drainage is water containing acidity, iron, manganese, aluminum, and other metals. It is caused by exposing coal and bedrock high in pyrite to oxygen and moisture as a result of mining operations.

The DOE's carbon sequestration program would focus forestation projects primarily on formerly mined lands. The non-point source pollutants of primary concern from coal mining are Acid Mine Drainage (AMD) and siltation from erosion of poorly revegetated mined lands. Acid drainage is water containing acidity, iron, manganese, aluminum, and other metals. It is caused by exposing coal and bedrock high in pyrite (iron-sulfide) to oxygen and moisture as a result of surface or underground mining operations. If produced in sufficient quantity, iron hydroxide and sulfuric acid, a result of chemical and biological reaction, may contaminate surface and ground water. For example, in 1997 Pennsylvania reported the single biggest water pollution problem was polluted water draining from abandoned coal mining operations, where over half of the streams that didn't meet water quality standards. More than 2,400 miles were degraded because of mine drainage (Rossman, 1997). One goal of mine reclamation is to minimize these pollutants.

Short-term soil erosion during site preparation activities could be avoided using soil conservation BMPs. Although long-term stabilization of the site is accomplished by planting trees, during initial stages some erosion may occur. To prevent short-term erosion, a tree-compatible ground cover mix that includes annual and perennial grasses and legumes can be planted (Burger and Zipper, 2002).

Reforestation projects on previously mined lands would have overall long-term positive impacts on associated nearby surface water quality by substantially reducing acid mine drainage and soil erosion that can contribute to sedimentation.

4.4.3.8 Co-Sequestration of H_2S and CO_2

Potential short-term (i.e. the construction stage) and long-term impacts related to the sequestering of both H_2S and CO_2 would be similar to the potential impacts for sequestering in coal seams, oil and gas fields, or saline groundwater formations. For the most part, surface facilities would be the same, with the exception that materials used for compressing and transporting the gas would have to resist the corrosive nature of H_2S. Short-term surface water impacts during construction of the surface facilities would be minor, relating to the activities necessary to clear the site. These construction activities would comply with state or local soil conservation permit requirements and BMPs to reduce sedimentation of nearby water bodies. Introduction of large areas of impervious surfaces such as paved roads and parking lots may require stormwater retention or detention basins to be constructed. Long-term surface water impacts from operations would be negligible to moderate depending upon the location of surface facilities. Disposing of process water by discharge to surface or groundwater would require an appropriate discharge permit and meet stringent standards in accordance with local, state and federal guidelines. These discharges would require routine monitoring and reporting. Long-term surface water impacts from operations would be negligible to moderate depending upon the location of surface facilities. Impacts associated with wastewater from compressing H_2S and CO_2 and recovery of oil could be mitigated with proper collection, treatment, monitoring and disposal methods.

4.4.4 Mitigation of Potential Adverse Impacts

The following BMPs are recommended to mitigate potential adverse impacts of carbon sequestration projects on surface water resources. BMPs are protective, economically feasible measures that can be developed and implemented, on a site-specific or project-specific basis, during the project planning and design, construction, and operation phases. These measures are aimed at reducing, preventing, or mitigating adverse environmental impacts to the surface water quality.

4.4.4.1 Project Planning and Design

- Select locations for equipment and pipelines away from floodplains, wetlands and other surface water bodies whenever possible. Delineate local wetlands as necessary.
- Design project components to minimize stormwater runoff. Where necessary, construct stormwater retention or detention basins.
- Investigate permit requirements under NPDES for construction and operations.
- Obtain soil conservation permits for construction activities and incorporate BMPs into construction specifications.
- Update facility stormwater management plans and Spill Prevention, Control and Countermeasures Plans as necessary.

4.4.4.2 Construction

Projects would require coverage under the NPDES Program for anticipated erosion and runoff resulting from site development activities. A General Construction Activity Storm Water Permit is an element of the NPDES program that would apply to projects. BMPs to reduce surface-water impacts associated with construction include:

- Placement of hay bales, silt fencing, straw wattles, and sediment traps to reduce erosion.
- Flagging and placing silt fencing around storm drains, wetlands and other sensitive areas.
- Storing oils, antifreeze and fuels in closed containers away from any surface drainages. Inspecting machinery daily for fluid leaks and spills.
- Minimizing areas of cleared and disturbed lands.
- Reclaiming disturbed soils as quickly as possible or applying protective covers.
- Existing drainage systems should not be altered, especially in sensitive areas such as erodible soils or steep slopes.
- On-site surface runoff control features should be designed to minimize the potential for increased localized soil erosion. Drainage ditches should be constructed only where necessary. Potential soil erosion should be controlled at culvert outlets with appropriate structures. Catch basins, drainage ditches, and culverts should be cleaned and maintained regularly.

4.4.4.3 Operation

- Maintaining good housekeeping procedures. Do not allow trash, debris, unused or broken equipment and materials, or hazardous wastes to accumulate or come into contact with storm water.
- Reporting and cleaning up spills of hazardous materials quickly.

4.4.5 Regional Considerations

Potential impacts on surface water resources from sequestration projects would be comparable among the various states. As described in Sections 2.3 and 2.4, the availability of CO_2 sources and potential sequestration sinks largely determines the applicability of various technologies in particular states and regions.

Construction aspects of all carbon sequestration technologies would require soil conservation permits and controls to minimize sedimentation of surface waters and construction. Depending on the size of the construction site, construction activities would also need a Phase I or Phase II General Construction Activity Storm Water Permit. Similarly, industrial sites under all technologies may be required to implement or amend a storm water management plan.

> Water discharges resulting from ECBM, EOR and co-sequestration activities could result in potentially moderate impacts to surface water quality.

The carbon sequestration program may result in new facilities to recover CBM. The CBM operations can generate substantial amounts of process water that may seek to discharge this water to groundwater or surface water. These projects would require permitting in accordance with state and federal NPDES provisions of the CWA.

4.4.6 Summary of Potential Impacts

Table 4-10 provides an overall qualitative assessment of potential impacts to surface water resources for each sequestration technology. For the most part, expected impacts would be expected to be negligible, with the exception of potentially moderate (short-term and widespread impacts resulting infrequently due to operator error) impacts to surface water quality from water produced by sequestration in coal seams, EOR, and the co-sequestration of H_2S and CO_2. Sequestration by reforestation of mined lands would have long-term beneficial impacts on surface water resources by reducing acid-mine drainage and soil erosion that can contribute to sedimentation of surface waters.

Table 4-10. Potential Impacts of Program Technologies on Surface Water Resources

Impact Considerations	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Surface water availability and uses	·	·	·	·	·	·	+	·
Surface water quality	·	·	○	○	·	·	+	○
Storm water drainage	·	·	·	·	·	·	+	·
Floodplains*	·	·	·	·	·	·	·	·
Wetlands	·	·	·	·	·	·	·	·

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.5 BIOLOGICAL RESOURCES

This section describes the potential impacts to biological resources that could occur during the implementation of carbon sequestration technologies. The biological resources that could be affected by sequestration technologies are described in Section 3.5. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.5.1 Impact Considerations

The types of ecological resources potentially affected by carbon sequestration projects depend on the specific location of the proposed project and its environmental setting. Ecological resources that may be affected include vegetation, fish, and wildlife, as well as their habitats. Affected biota may include species that have been designated as threatened, endangered, or species of special concern by FWS or state natural resource agencies. The ecological provinces were compared with areas of the Regional Partnerships. This provides a broad indication of the types of plant communities and wildlife species that could be affected by carbon sequestration projects. The criteria that have been used to assess potential adverse impacts on biological resources are described below. Impacts were assessed using the definitions found in Section 4.1.1. Short-term impacts for biological resources are defined as impacts occurring for the duration of the construction phase. Localized impacts for biological resources are defined as those occurring within the project footprint.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Cause substantial displacement of terrestrial communities or loss of habitat.
- Diminish the value of habitat for wildlife or plants to an unusable level.
- Cause a native wildlife population to drop below self-sustaining levels.
- Substantially interfere with the movement of any native resident or migratory wildlife species for more than one reproductive season.
- Conflict with applicable management plans for wildlife and habitat.
- Alter drainage patterns causing the displacement of fish species.
- Diminish the value of habitat for fish species to an unusable level.
- Cause a native fish population to drop below self-sustaining levels.
- Substantially interfere with the movement of any native resident or migratory fish species for more than one reproductive season.
- Conflict with applicable management plans for aquatic biota and habitat.
- Cause unmitigated temporary or long-term loss of a wetland habitat.
- Cause the introduction of non-native wetland plant species.

- Adversely affect or displace special status species.
- Cause encroachment or an adverse effect on a designated critical habitat.

Qualitative descriptions of the potential impacts are presented in the following sections. Most impacts can only be fully evaluated on a site-specific level and on the basis of a variety of factors, such as the status of native and invasive plant and animal populations, the types of habitats that would be disturbed, and the nature of the disturbance.

4.5.2 Regulatory Framework

Carbon sequestration projects would need to consider applicable federal, state, and local laws and regulations concerning biological resources. Major federal laws and regulations for biological resources are listed in Table 4-11.

Table 4-11. Major Laws and Regulatory Requirements for Biological Resources

Law/Regulation	Key Elements
Endangered Species Act of 1973 (16 USC § 1531)	This Act determines and protects both plant/animal species and their critical habitats that are threatened or endangered. The Act prohibits any Federal action that may jeopardize such species and provides for the designation of critical habitat of such species wherein no action is to be taken concerning degradation of the habitat. The Act requires a biological assessment of Federal agency actions when an endangered or threatened species may be present in the area affected by the actions.
Bald Eagle Protection Act of 1940, as Amended (16 USC § 668).	This Act, amended in 1972, prohibits the killing, harassment, possession, or selling of bald eagles. The Act also imposes penalties for the possession of bald eagles or eagle parts taken from birds after June 1940. The Act provides an exemption for the use of bald eagle parts in American Indian religious ceremonies, provided that the appropriate permit is granted to the tribe by the USFWS.
Executive Order 13186 - Responsibilities of Federal Agencies To Protect Migratory Birds (10 January 2001)	Each Federal agency taking actions that have, or are likely to have, a measurable negative effect on migratory bird populations is directed to develop and implement, within 2 years, a Memorandum of Understanding (MOU) with USFWS that promotes the conservation of migratory bird populations.
Executive Order 13112 Invasive Species	On February 3, 1999, the President issued Executive Order 13112 to prevent the introduction of invasive species and provide for their control, and to minimize the economic, ecological, and human impacts. In accordance with Executive Order 13112 on invasive species, native plant species would be used in the landscaping and in the seed mixes where practicable.

4.5.3 Generalized Siting and Operational Impacts of Technologies

4.5.3.1 Post-combustion Capture

Construction and operation of the Post-Combustion CO_2 Capture model project would entail retrofitting an existing power plant or other CO_2 source, as described in Section 2.5. It is anticipated that the post-combustion capture facility would be constructed immediately adjacent to the existing power plant and share infrastructure, such as access roads and utility requirements, and resources, such as cooling water and cooling towers, if applicable. The site would most likely be located in an industrial setting on land that has been previously disturbed.

A detailed evaluation of potential impacts would depend upon the specific location for a representative project. In general, the following types of impacts may be expected. Because the facility would likely be constructed on or adjacent to an existing industrial facility, the potential impacts are expected to be negligible. Existing vegetation would be removed, destroying habitat for any wildlife that may inhabit the area, which may include reptiles, amphibians, birds, and small mammals depending on the exact location.

If there were similar habitat adjacent to the proposed site, the wildlife would be displaced. If, however, suitable habitat were not available adjacent to the proposed site, the less mobile wildlife most likely would not survive. While the potential presence of protected species in industrial areas would be unlikely, informal consultation with the USFWS and appropriate state and local agencies would take place and, if necessary, surveys for protected species would be implemented.

If the project area includes wetlands, consultation with the U.S Army Corp of Engineers would determine whether the wetlands are jurisdictional and, if so, what protective measures must be implemented. If the wetlands have been previously impacted or are of low quality, an appropriate mitigation may be the replacement of wetlands in another suitable location.

Most of the waste materials generated by this facility would be disposed of offsite in licensed landfill or treatment facilities. Cooling water from the facility may be combined with cooling water from the power plant and discharged to local receiving waters. Modification of discharge permits for the existing facilities would be necessary to include the discharge from the CO_2 capture facility.

4.5.3.2 CO_2 Compression and Transport

> New CO_2 pipelines should be sited to avoid wetlands and minimize stream crossings. Existing rights-of-way should be used whenever possible.

It is assumed that the equipment for compressing CO_2 for transport to a sequestration site would be co-located with the CO_2 capture equipment. The incremental impacts of construction and operation of CO_2 compression facility would be small compared to the potential impacts from construction and operation of the CO_2 capture facilities in terms of amount of land disturbed.

Standard construction techniques and BMPs would be used to minimize impacts to biological resources. Pipelines can be sited to avoid wetlands and minimize crossing of streams. Impacts on vegetation would be localized, restricted to the rights-of-way, and temporary. Existing rights-of-way would be used whenever possible. If the pipeline route were to traverse a forest, trees would be clear-cut along the rights-of-way, and new trees would not be allowed to grow in the ROW during operation of the pipeline. It is more likely that regulatory conditions would guide the location of compression equipment and pipelines away from wetlands and areas where protected species are known to reside. Subsequently, compression and transport projects are more likely to result in minor adverse (short-term and localized) impacts to terrestrial communities during the construction phase. It is assumed that piping would be buried underground and areas reseeded. Because of regulatory processes requiring pre-construction surveys for species of concern and the costs associated with wetland permitting and mitigation, impacts to aquatic communities, wetland communities and special status species are expected be negligible.

The alternative use of compressed gas trucks to transport CO_2 to sequestration sites via existing highways would have negligible impacts on biological resources.

4.5.3.3 Sequestration in Coal Seams

This technology entails the injection of CO_2 into coal seams and the subsequent recovery of methane from the coalbed. It is assumed that a feasible project would be implemented in an area previously disturbed by coal mining or CBM recovery projects. Therefore, much of the infrastructure would exist, such as access roads, ROW for pipelines, and utilities required, for the CO_2 sequestration project. Additional wells may be required, which would involve construction of new well pads and drilling of wells. Existing wells may be converted to CO_2 injection or monitoring wells.

During construction, adverse ecological impacts may occur from erosion and runoff; fugitive dust; noise; introduction and spread of invasive vegetation; modification, fragmentation, and reduction of habitat; mortality of biota; exposure to contaminants; and interference with behavioral activities. Site clearing and grading, along with construction of drill pads, ancillary facilities, pipelines, and access roads, could reduce, fragment, or dramatically alter existing habitat in the disturbed portions of the project area. The types of impacts from construction are expected to be similar to those that have occurred at comparable construction projects. The construction impacts of most concern with regard to ecological resources are those associated with the reduction, modification, and fragmentation of habitat.

In general, potential adverse impacts on both the flora and fauna within and surrounding the project area would most likely be minor and restricted to the immediate vicinity. This same conclusion was reached in the *Environmental Assessment for Enhanced Coalbed Methane Production and Sequestration of CO_2 in Unmineable Coal Seams* (DOE, 2002).

Potential impacts associated with construction and operation phases of a coal seam sequestration project and associated impact avoidance strategies are discussed below. Assuming proper planning, site surveys, BMPs, and restoration practices are instituted, impacts to terrestrial communities, wetland communities and special status species are expected to be negligible. Due to the common practice of discharging wastewater from ECBM extraction to surface waters, there is potential for minor adverse (localized and short-term) impacts to aquatic communities.

4.5.3.3.1 Construction Effects on Vegetation

A number of construction-associated activities may adversely impact vegetation at a site for sequestering CO_2 in coal seams. These activities include the clearing and grading of vegetated areas for construction of drill pads, ancillary facilities, access roads and pipelines. Impacts associated with these activities may be of long- or short-term duration and would largely be localized to the immediate project area. The introduction of invasive vegetation into disturbed areas of the project site, and possibly into surrounding areas, could result in long-term impacts to the native plant community at the site, access routes, and in surrounding areas. These potential impacts are summarized in Table 4-12.

Table 4-12. Potential Effects of Project Construction on Vegetation

Ecological Stressor	Associated Project Activity	Potential Effect	Extent and Duration of Effect
Direct injury or destruction of vegetation	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Destruction and injury of vegetation leading to reduced productivity and reproductive success	Permanent loss of vegetation within footprint of drill pads, ancillary facilities, and access roads. Short-term loss in areas adjacent to foot print.
Fugitive Dust	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Reduced productivity of plant caused by reduced photosynthesis and related effects	Short-term, limited to construction site and surrounding area.
Exposure to contaminants	Accidental spills of fuel or lubricating oil during equipment maintenance.	Exposure may affect plant survival, reproduction, development, or growth	Short-term, localized to spill area
Invasive vegetation	Site clearing and grading	Establishment of non-native and/or invasive vegetation; decrease in natural vegetation and habitat quality	Long-term in areas cleared of natural vegetation but not used for permanent facilities.

The nature of the construction impacts to vegetation would be comparable for all states, while the extent of the impacts would depend on the size of the project. Clearing, grading, and construction activities would result in direct injury to and/or loss of vegetation, thereby altering or eliminating the plant communities in the permanently disturbed portions of the project site. Impacts to vegetation in the temporary construction areas would be short-term. Native vegetation would be expected to regenerate following completion of construction activities. Additional impacts on vegetation communities could occur from soil compaction, loss of topsoil, and removal of or reductions in the seed bank. The clearing of trees adjacent to a proposed project site or within access road rights-of-way may also be required.

The temporary disturbance of vegetation in some project areas during facility construction would not be considered ecologically significant. Nevertheless, it could take several years for temporarily affected areas to recover (Erickson et al., 2003), and some types of habitat may never fully recover from disturbance.

Fugitive dust generated during clearing, grading, and construction activities may impact vegetation immediately surrounding the project area. A dust coating on leaves has been shown to increase leaf temperature, which in turn increases transpiration rate or water loss from the leaf. Leaf temperature is one of the major parameters controlling photosynthesis. Dust coating on leaves has also been shown to reduce photosynthesis through shading (Hirano et al., 1995).

Fugitive dust generation may be relatively high at carbon sequestration project sites located in the more arid ecological provinces. However, the generation of fugitive dust during the construction phase of a carbon sequestration project can be expected to be short-term and localized to the immediate area of the ground disturbance.

Construction equipment would need to be refueled, and some hazardous materials or wastes, such as waste paints and degreasing agents, may be generated during the construction phase. Accidental spills of fuel, lubricating oils or hazardous materials could result in damage to vegetation. Re-establishment of the vegetation may be delayed because of residual soil contamination. These impacts would be expected to be small and localized. With the removal of contaminated soil, residual effects would be minimized.

Land that has been cleared at a carbon sequestration project site may create an opportunity for invasive plant species to become established. The magnitude and extent of invasive plant establishment would be a function of the aggressiveness of the introduced plants, the number and frequency of seed introductions to a particular area, and the availability of suitable conditions (e.g., disturbed habitat) for colonization by the introduced seeds. Seeds can be easily introduced into construction areas and the surrounding vegetation communities via construction vehicles that have been in other areas where invasive species are present. Invasive vegetation could also be introduced into the soils used to backfill and grade portions of a construction site. Depending on the source of the fill, it may contain seeds, cuttings, or spores of invasive plant species and thus provide an opportunity for introduction of invasive species. The establishment of invasive vegetation may be limited by early detection and subsequent eradication of the plants.

4.5.3.3.2 Construction Effects on Wildlife

The wildlife that may be affected by construction of a carbon sequestration project would depend on the ecological province in which the project is planned and the nature and extent of the habitats in the project area and surrounding vicinity. Construction activities may adversely affect wildlife through habitat reduction, alteration, or fragmentation, as well as cause direct injury or mortality of wildlife, cause a decrease in water quality from erosion and runoff, create disturbing noise, and interfere with behavioral activities. Potential effects of construction on wildlife are summarized in Table 4-13.

Table 4-13. Potential Effects of Project Construction on Wildlife

Ecological Stressor	Associated Project Activity	Potential Effect	Extent and Duration of Effect
Habitat Disturbance	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Reduction or alteration of habitat in and around the construction area	Long-term habitat reduction within construction footprint. Long-term reduction of habitat quality on adjacent areas.
Direct Injury or Mortality	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Destruction and injury of wildlife	Short-term effect on wildlife population
Erosion and Runoff	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Reduction in habitat quality for amphibians using surface waters. Wildlife drinking water supply may be affected	Short-term, may extend beyond site boundaries
Noise	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Disturbance of foraging and reproductive behaviors; Habitat avoidance by birds and mammals	Short-term, limited to the site and immediately surrounding area.
Interference with behavioral activities	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Disturbance of migratory movements. Disturbance of foraging and/or reproductive behaviors	Short-term

The construction involved with a coal seam carbon sequestration project may impact wildlife through the reduction, alteration, or fragmentation of habitat. This represents the greatest construction-related impact to onsite wildlife. All existing habitats within the construction footprints of drill pads and ancillary facilities and along access road corridors would be destroyed. The construction of a coal seam carbon sequestration project would not only result in the direct reduction or alteration of wildlife habitat within the project footprint but could also affect the diversity and abundance of area wildlife through the fragmentation of existing habitats. The nature of the construction impacts to vegetation would be similar in all states, while the extent of the impacts would depend on the size of the project. The extent of habitat destruction would be the same as the impact on vegetation presented above.

The effects of habitat reduction, disturbance, or fragmentation on wildlife would be related to the type and abundance of the habitats affected and to the wildlife that occur in those habitats. For example, reduction, disturbance, or fragmentation of habitats that are not common or well represented in the area surrounding the site may have a greater impact on wildlife inhabitants than common habitats that are well represented in the surrounding area. Fewer impacts would be expected for projects located on previously disturbed lands. Forest interior species and some terrestrial birds, such as pheasants, turkeys, and grouse, may be especially affected by habitat fragmentation.

Clearing and grading activities may result in the direct injury or death of wildlife that are not mobile enough to avoid construction operations (e.g., reptiles, small mammals, and young), that utilize burrows (e.g., ground squirrels, burrowing owl), or that are defending nest sites (such as ground-nesting birds). More mobile species of wildlife, such as deer and adult birds, would avoid the initial clearing activity by moving into habitats in adjacent areas. This may result in increased competition for resources in adjacent habitats and, in the worst-case scenario, may preclude the incorporation of the displaced individual into the resident populations if the surrounding habitat has reached carrying capacity.

The overall affect of construction-related injury or death on local wildlife populations would depend on a number of factors. The number and types of species present at the site that could be affected would be a function of the habitat that could be disturbed. The abundance of the affected species on the site and in surrounding areas would have a direct influence on population level effects. Impacts to common and abundant species may be expected to have less population-level effects than would the loss of individuals from a species that is uncommon. The greater the size of the project site, the greater the potential for more individual wildlife to be injured or killed. Finally, the timing of construction activities could directly affect the number of individual wildlife injured. For example, construction during the reproductive period of ground-nesting birds, such as sage-grouse, would have a greater potential to kill or injure birds than would construction at a different time.

Construction activities may result in increased erosion and runoff from freshly cleared and graded sites. This erosion and runoff could reduce water quality in onsite and surrounding water bodies that are used by amphibians, thereby affecting their reproduction, growth, and survival. The potential for water quality impacts during construction would be short-term, for the duration of construction activities and post-construction soil stabilization (e.g., re-establishment of natural or man-made ground cover). Any impacts to amphibian populations would be localized to the surface waters receiving site runoff. Although the potential for runoff would be temporary, pending completion of construction activities and stabilization of disturbed areas with vegetative cover, erosion could result in significant impacts to local amphibian populations if an entire recruitment class is eliminated (e.g., complete recruitment failure for a given year because of siltation of eggs or mortality of aquatic larvae).

Principal sources of noise during construction activities would include truck traffic, operation of heavy machinery, and foundation blasting (if necessary). The most adverse impacts associated with construction noise could occur if critical life-cycle activities were disrupted (e.g., mating and nesting) (NWCC, 2002). If birds were disturbed sufficiently during the nesting season to cause displacement, nest or brood abandonment might occur, and the eggs and young of displaced birds would be more susceptible to cold or predators. Increased noise levels due to construction activities would be temporary. Noise intensity decreases exponentially with distance, so the effects of increased noise levels would be limited to the site and the immediate surrounding area.

Construction activities at a coal seam carbon sequestration project site may affect local wildlife by disturbing normal behavioral activities such as foraging, mating, and nesting. Wildlife may avoid foraging, mating, or nesting or vacate active nest sites in areas affected by construction. In addition, active construction may also affect movements of some birds and mammals; for example, they may avoid a localized migratory route because of ongoing construction. It would be expected that mobile wildlife would avoid the construction area for the duration of construction, thus the impacts would be short-term and restricted to the immediate construction area.

4.5.3.3.3 Construction Effects on Wetland and Aquatic Biota

A coal seam carbon sequestration project could be sited in an area with surface water features such as streams or rivers, lakes, ponds, and wetlands. The layout of the project would be flexible enough that surface water features could be avoided in siting drill pads and ancillary facilities, however, the situation might occur that access roads or pipelines may have to cross a stream, river, or wetland. The types of aquatic biota and wetlands that could be affected would be a function of the ecological province in which the facility is located and the site-specific environmental conditions present at the facility location. Construction activities may adversely affect wetlands and aquatic biota through habitat disturbance, direct mortality or injury of biota, erosion and runoff, and interference with migratory movements (Table 4-14). Except for the construction of stream crossings for access routes or the unavoidable location of pipelines in a wetland, construction within wetlands or other aquatic habitats would be largely prohibited. Thus, most potential impacts to wetlands and aquatic biota would be indirect.

The overall impact of construction activities on wetlands and aquatic resources would depend on the type and amount of aquatic habitat that would be disturbed, the nature of the disturbance (e.g., grading and filling, or erosion in construction support areas), and the aquatic biota that occupy the project site and surrounding areas. The construction of stream crossings would directly impact aquatic habitat and biota within the crossing footprint. This impact would be long-term, but of relatively small extent and magnitude.

Table 4-14. Potential Effects of Project Construction on Aquatic and Wetland Habitat

Ecological Stressor	Associated Project Activity	Potential Effect	Extent and Duration of Effect
Habitat Disturbance	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Reduction or alteration of habitat in and around, affecting all aquatic biota	Long-term habitat reduction within construction footprint. Long-term reduction of habitat quality on adjacent areas.
Direct Injury or Mortality	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Destruction and injury of aquatic biota	Short-term effect on aquatic populations
Erosion and Runoff	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Decreased water quality, including increased turbidity and siltation, decreased light penetration, and decreased dissolved oxygen levels; siltation of eggs, larvae, and/or adults of aquatic invertebrates and vertebrates; decreased primary productivity; decreased wetland function.	Short-term, localized, may extend beyond site boundaries
Interference with behavioral activities	Site clearing and grading, Construction of support facilities and access roads; Construction of drill pads	Disturbance of migratory movements. Disturbance of foraging and/or reproductive behaviors	Short-term

Compliance with the CWA regarding activities in wetlands would limit the likelihood of construction occurring in or impacting wetland habitats. Otherwise, clearing, grading, and construction activities may result in direct disturbance or reduction of aquatic and wetland habitats that may be present within construction footprint, including access roads and pipelines. Impacts would be expected only if the overall site layout was not sufficiently flexible to avoid crossing a stream or wetland. In this case, site clearing and grading could result in the reduction of aquatic and wetland habitats. Wetlands and other aquatic habitats may also be affected if erosion from construction areas results in runoff and siltation thus decreasing water quality and silting-over biota.

Water quality and aquatic habitat may be affected if construction activities cause an increase in runoff or erosion of soils. Turbidity and sedimentation from erosion are part of the natural cycle of physical processes in water bodies, and most aquatic organisms tolerate short-term changes in these parameters. Generally, adverse impacts only occur if sediment loads are unusually high, last for extended periods of time, or occur at unusual times of the year. Increased sediment can decrease the feeding efficiency of aquatic biota; reduce plant, invertebrate, and fish abundance; and decrease fish spawning success by adversely affecting the survival of eggs and fry. Erosion and runoff could also affect wetland hydrology, function, and water quality.

While any impacts to aquatic biota would be localized to the surface waters receiving site runoff, significant impacts to local populations could result if the magnitude and duration of the runoff were sufficiently high. However, the amount of erosion and runoff into aquatic habitats at, and in the vicinity of, the site is expected to be very small. Impacts from erosion and runoff are expected to be localized and temporary. The potential for water quality impacts during construction would be short term (the duration of construction activities), and post-construction soil stabilization activities (e.g., re-establishment of natural or man-made ground cover) would greatly reduce or eliminate further erosion and runoff from the site. As previously discussed, projects would be subject to the CWA, and if a project was expected to disturb 5 or more acres (2 or more hectares) of wetland, a Storm Water Pollution Prevention Plan (SWPPP) and NPDES compliance permit would be needed.

4.5.3.3.4 Construction Effects on Threatened and Endangered Species

The potential for construction activities to affect threatened, endangered, and sensitive species would be dependant on a number of factors, including the ecological province in which the project would be located and, more importantly, the specific location of the site. Prior to any construction activities on the selected site, including clearing and grubbing, informal consultation with the USFWS or corresponding state agency would take place. If necessary, field surveys specifically designed to detect the presence or absence of protected plant and wildlife species would be implemented. Since many plants cannot be accurately identified unless flowering, the surveys may have to span several seasons.

Direct impacts on threatened, endangered, and sensitive wildlife species could include reduction or fragmentation of habitat, reduction or displacement of habitat features such as cover and forage, exposure to contaminants (e.g., diesel fuel) from a spill, and destruction of individual biota (e.g., from clearing and grubbing activities or from vehicle collisions). In addition, critical habitat, as designated by the FWS, is protected. Because of the regulatory requirements of the ESA and various state regulations, and of other resource-specific regulations and guidelines, appropriate survey, avoidance, and mitigation measures would be identified and implemented prior to any construction activities to avoid impacting any sensitive species or the habitats on which they rely.

4.5.3.3.5 Operation Effects on Vegetation

It is assumed that the project would be implemented in an area with existing developed coal resources or CBM production operation. Also, an economically feasible project would be sited near a source of CO_2 (e.g. an existing fossil fuel power plant or gas plant).

The permanent loss of vegetation would be considered a minor impact to the region. Whenever possible, existing wells would be modified to meet the needs of the project, thus reducing the number of new well pads required. Sensitive lands and vegetation would be avoided. There also consists the potential of damage to vegetation due to accidental spillage of fuel, lubricating oil, or other hazardous materials. The adverse effects of accidental spills would be contained to the immediate area. All contaminated soils would be removed and replaced with clean soils.

4.5.3.3.6 Operation Effects on Wildlife

The effects of operation of the project on wildlife within the site and surrounding area would likely be minor, primarily because of the size of the permanently disturbed areas compared to the size of the site. The probability of causing harmful fragmentation of existing habitat or impeding the movement of wildlife would be very low.

Maintenance of the various well sites, access roads, and ancillary facilities may entail mowing to control vegetation immediately surrounding area. This would most likely preclude much of the native vegetation and may allow non-native, invasive vegetation to become established. Appropriate measures may have to be taken to minimize the harmful effects invasive species may have.

The CO_2 would be injected into the coal seam under pressure by pumps. The CO_2 compressor and pumps would generate noise. On-site electric generators, if required, would also generate noise. This noise would be disruptive to wildlife in the immediate vicinity of the site. The noise would be relatively constant; therefore, much of the wildlife would habituate to the noise. There may be animals, such as some birds and small mammals that may continually avoid the vicinity of the noise. This effect would be considered minor because of the limited size of the area that would contain facilities that generate the noise compared to the size of the whole project site. In addition, noise levels would be reduced exponentially with distance from the source, further limiting the size of the affected area.

4.5.3.3.7 Operation Effects on Wetland and Aquatic Biota

If the project were developed in the vicinity of surface water resources or wetlands, there would be a potential for adverse impacts on these resources, primarily due to the potential for decreased water quality caused by increased erosion and runoff from the site and the introduction of contaminants to the water body or wetland. Potential operational impacts on wetlands and aquatic resources would be expected to be of lesser magnitude and significance than impacts that could be incurred during construction of the project. Wetlands and aquatic resources could be affected by site maintenance activities that involve mowing or cutting of wetland and riparian vegetation and decreased water quality due to surface runoff from the site.

4.5.3.4 Sequestration in Depleted Oil and Gas Reserves

A project for sequestering CO_2 in depleted oil and gas reserves would be implemented at existing oil and/or gas fields. There are several commercial installations using CO_2 for EOR in operation. The potential impacts on biological resources would be very similar to those described in Section 4.5.2.3, Sequestration in Coal Seams.

4.5.3.5 Sequestration in Saline Formations

A project for sequestering CO_2 in a saline formation would most likely be implemented at an existing oil and/or gas field. Saline formations are often associated with an oil field and much of the infrastructure for the sequestration of CO_2 would already be in place. The potential impacts to biological resources would be very similar to those for carbon sequestration in coal seams.

The DOE prepared an Environmental Assessment for *Pilot Experiment for Geological Sequestration of Carbon Dioxide in Saline Aquifer Brine Formations* (DOE, 2003), a project proposed for an existing oil field in eastern Texas. This document concluded that potential impacts from surface activities from this pilot experiment would be minor and comparable to on-going activities at the site. It is expected that a larger, commercial-scale project would have greater environmental impacts than a field validation project, especially for saline formation sequestration projects that would not be located on an existing industrial site.

Assuming proper planning, site surveys, BMPs, and restoration practices are instituted, impacts to terrestrial communities, aquatic communities, wetland communities and special status species are expected to be negligible.

4.5.3.6 Sequestration in Basalt Formations

Unlike EOR or coal seam sequestration projects, projects for sequestering CO_2 in basalt formations would likely be located in areas that were not subject to previous resource extraction. Therefore, the likelihood of potentially siting projects in areas with higher ecological value is somewhat higher. The potential impacts on biological resources would be very similar to those described in Section 4.5.2.3.

Because the Columbia River Basalt Group (CRBG) in the Pacific Northwest is more highly characterized for potential sequestration activities than others in the U.S., it is likely that first commercial sequestration projects would be attempted in the Pacific Northwest. The presence of another large basalt formation, the Snake River Plain, also supports the assumption that projects, and subsequently ecological impacts, would probably be greater in the Pacific Northwest than in other regions.

Assuming proper planning, site surveys, BMPs, and restoration practices are instituted, impacts to terrestrial communities, aquatic communities, wetland communities and special status species are expected to be negligible.

4.5.3.7 Terrestrial Sequestration – Reforestation

For the purposes of this document, the sequestration of CO_2 in terrestrial systems is limited to the reclamation of land that has been previously mined. In many cases grasses are planted on newly recontoured land as an effective means of erosion control. Reforestation would entail the planting of trees, preferably trees native to the area, in the mined area (Section 2.5).

> Reforestation would increase or re-establish edge environment, which is the transition areas between forest and grasslands. Many predator species and small mammals use this edge habitat for hunting.

Potential site-specific impacts cannot be accurately assessed until a specific location for a reforestation project has been chosen. However, because of the nature of such a project, i.e., the planting of trees in a clear-cut area, the overall impacts to biotic resources would be expected to be beneficial. In many cases, clear-cutting an area for mining entails removal of the climax or near-climax ecosystem, the pine or hardwood forest. Reclamation of the mined area begins with the planting of grasses, primarily for rapid control of erosion. In nature, grasses and shrubs are the pioneer plants, the first to become established in a disturbed area. Reforestation, especially with native species of trees, decreases the time it takes for the area to reach climax or near-climax ecosystem.

Planting trees in a reclaimed mined area would increase the biodiversity of the area, resulting in a beneficial impact to terrestrial communities. As the trees grow and mature, they would out-compete the grasses for resources, primarily by shading the grasses from sun. Forest ecosystems support a greater diversity of both plants and animals than grasslands. However, certain species that may have invaded the grasslands, such as prairie species, would be eliminated from the area as trees and undergrowth replace the grasses.

Reforestation would increase or re-establish edge environment, which is the transition area between the forest and grasslands. Many predator species, such as raptors, and small mammals, such as fox, use this edge habitat for hunting. The forest provides cover and trees for roosting and the fields are habitat for small mammal prey species, such as mice, voles, and rabbits.

Reforestation also would likely have a beneficial impact on the aquatic habitat of streams. Trees shade the water, which reduces water temperature. In addition, the forest vegetation furthers the control of runoff, thus reducing the sediment loading of the stream and ponds. Trees and vegetation that grow along the banks of rivers, streams, and ponds may also provide increased cover for fish and other aquatic species. Protection of headwater streams may be particularly beneficial. Headwater streams are important ecologically, because they contain both diverse invertebrate assemblages and some unique aquatic species. Headwater streams also provide organic energy that is critical to fish and other aquatic species throughout an entire river.

Terrestrial reforestation projects would have a negligible impact on wetlands, as projects would generally be located in upland areas. Impacts to special status species are also expected to be negligible, as these previously disturbed mining areas are less likely to currently support these species in general.

4.5.3.8 Co-Sequestration of H_2S and CO_2

Potential short-term, (i.e. the construction stage), and long-term impacts related to the sequestering of both H_2S and CO_2 would be similar to the potential impacts for sequestering in coal seams, oil and gas fields, or saline formations. For the most part, surface facilities would be the same, with the exception that materials used for compressing and transporting the gas would have to resist the corrosive nature of H_2S. Potential impacts to terrestrial and aquatic habitats and biota would be expected to be negligible. Potential impacts to protected species would be negligible if the appropriate mitigation measures are implemented.

4.5.3.9 Biological Effects of Seismic Imaging

Seismic imaging may be an essential pre-requisite to the siting of new geologic sequestration projects. Although seismic imaging is a relatively mature technology, DOE's Program will either directly support further research in this area or indirectly support new seismic surveys through funding of related sequestration field validation projects where further characterization of subsurface geology is needed. As carbon sequestration technology becomes commercialized, it is also reasonable to assume that seismic imaging would be used by private industry to characterize potential geologic sinks. Therefore, it is important that any future proponents of projects involving seismic surveys understand and conduct a review (including NEPA study as required) of any potential ecological impacts that may occur and obtain any necessary state or local permits prior to initiating these surveys. This discussion of impacts of seismic surveys focuses on land surveys, as the Program will focus primarily on on-shore activities. The impacts of seismic surveys on marine mammals is well documented and any seismic surveys conducted in areas that could affect marine life would also require environmental studies and permits as applicable.

> Reforestation would increase or re-establish edge environment, which is the transition areas between forest and grasslands. Many predator species and small mammals use this edge habitat for hunting.

Seismic imaging or exploration involves sending man-made seismic waves into the Earth. These waves reflect from the Earth's geologic layering and features, which cause echoes or reflections that travel back up to the Earth's surface. Electromagnetic transducers, or geophones, pick up the echoes and convert them into electrical signals. These signals are then processed into images of the Earth's shallow structures, and interpreted by geologists or geophysicists to determine what types of rocks may be located below the testing area, and in the case of oil exploration, determine if those rocks or formation contain hydrocarbon deposits (Zimmermann, 2005).

Seismic exploration uses either huge vibroseis trucks weighing 56,000 pounds, with heavy steel vibrators on them, or explosives, to produce sounds at or near the surface. This is done along potentially thousands of "shot" points along lines that are surveyed across the study area. There are many potential adverse environmental effects from seismic exploration. This 3-D seismic testing is more effective in determining geologic structures than 2-D surveying, but can have more impact. The 3-D seismic crews are larger, and there are potentially more vehicles traversing the area because the grid is tighter, requiring vehicle travel to lay out grids of recording equipment roughly 1,000 to 1,400 feet apart. By contrast, conventional seismic lines are spaced six to ten miles apart (VanTuyn, 2000).

Seismic imaging projects can potentially cover up to 100,000 square miles. Seismic imaging may be conducted in the planning stages of a carbon sequestration project to accurately locate suitable formations and could be used after project initiation to monitor the sequestered CO_2. Both the site characterization and monitoring phases would require imaging operations that extend beyond the CO_2 storage site. The extent of the seismic imaging area is generally larger than the storage site in order to create an image of CO_2 accumulation. The area predicted to be disturbed under each model project in Section 2.5 does not take into account disturbance as a result of seismic imaging. Therefore, if a project will use seismic imaging, it is important to note that the areal extent of disturbance would be greater than the target reservoir and that the area could be subject to repeated seismic imaging.

In an Environmental Assessment for the WesternGeco Horse Point 3-D Seismic Exploration Project, it was estimated that 0.3 percent of the project area would be involved with surface disturbance (or 65 acres disturbed over the 19,840 acre study area). However, this project utilized shot hole techniques where no large vibroseis trucks were involved, no dozing or heavy equipment was used, and portable drill equipment was transported by truck, buggy or helicopter depending on the terrain to minimize off-road travel (BLM, 2002). Because this project used a less vehicle-intensive method to conduct the testing, this percentage of land disturbed would represent the low-end range of land potentially disturbed by seismic imaging.

Although the testing is relatively short in duration, potentially long-term impacts could result from the creation of dirt roads through ecologically sensitive areas. Heavy vehicles (vibroseis trucks, drill rigs, ATV's for placing the geophones) involved in the seismic testing are usually driven cross-country, resulting in depressions in soil and crushed vegetation that offer some indication of where vehicles used for the seismic project have driven. The main concern relating to road or two-track creation is that these newly formed paths could be used later by recreational off-road vehicles. If these roads are used frequently by off-road vehicles, the ecological impacts could become much more severe and apparent to wildlife, soil and vegetation (Zimmermann, 2005). Creating roads through natural areas could potentially lead to habitat fragmentation.

This surface-disturbing vehicle travel has the potential to also spread noxious weeds. Seeds transported by vehicles from outside the study area, some amount of surface disturbance and disruption of existing vegetation can create opportunities for new infestations of non-native invasive species.

Seismic surveys may also cause impacts to birds, including: nest abandonment (resulting from noise and human disturbance), direct mortality, reproductive failure, displacement, and destruction of nests (particularly for ground nesting birds). Shrub nesting birds may be affected due to the destruction of vegetation along seismic lines (BLM, 2002). Noise and human presence may cause other wildlife to move away from the study area as well.

In 1999, fieldwork conducted at Sabine National Wildlife Refuge studied the impacts of 3-D seismic operations on marsh soils and plants. Preliminary analyses indicated that immediately following the survey, the maximum vegetation height decreased within the survey zone and increased on control sites. Futher, in one of the two impoundments studied, *Spartina patens* (salt-meadow cordgrass) cover decreased in the impact zone but was unaffected on the control site. The results showed that 3-D seismic exploration flattens vegetation and can decrease cover of dominant plant species (Howard, 1999).

Overall, seismic surveys can result in some temporary and some potentially lasting adverse effects on wildlife, plants and habitat. Therefore, seismic survey plans should undergo environmental review before testing is authorized and conducted.

4.5.4 Mitigation of Potential Adverse Impacts

Potential impacts on biological resources from the construction and operation of a coal seam carbon sequestration project have been identified and evaluated to the extent possible without knowledge of a specific site. These potential impacts would be comparable for other land-disturbing projects as described in the preceding sections. There are a number of BMPs and mitigation measures that may be implemented for carbon sequestration projects to reduce or minimize potential ecological impacts. If appropriate, the monitoring of sensitive biological resources during the construction and operation of a carbon sequestration project can be implemented to support the identification and avoidance of potential adverse impacts before they become problematic. Monitoring data can be used to track the condition of ecological resources, to identify the onset of impacts, and to direct appropriate site management responses to address those impacts.

The following sections identify BMPs and mitigation measures that may be appropriate for minimizing potential impacts associated with carbon sequestration projects.

4.5.4.1 Project Planning and Design

BMPs and mitigation measures should be considered during the planning and design phase of the carbon sequestration project to minimize or avoid adverse impacts of the construction and operation of individual facility structures. The following measures should be incorporated into siting of individual structure and facilities of a carbon sequestration project:

- Identify important, sensitive, or unique habitat and biota in the project vicinity and, to the extent feasible, site and design the project to minimize or mitigate potential impacts to these resources. The design and siting of the facility should follow appropriate guidance and requirements of federal and state resource agencies, such as USFWS and USACE, as available and applicable.
- Contact appropriate agencies early in the siting and planning process to identify potentially sensitive ecological resources, such as protected species, critical habitat, or wetlands that may be present in the area of the carbon sequestration project.
- Conduct site walkovers or surveys for federally and state-protected species and other species of concern within the project area as directed by USFWS and the appropriate state agencies.
- Identify important, sensitive, or unique habitats in the vicinity of the project.
- Locate well pads, access roads, pipelines, and ancillary facilities in previously disturbed areas or areas least likely to impact important, sensitive, unique or designated critical habitats (such as wetlands and sagebrush habitat).
- Utilize existing rights-of-way for roads, pipelines, and utilities to the maximum extent feasible.
- Site individual project facilities and new rights-of-way for access roads, pipelines and utilities to avoid high quality habitats and minimize habitat fragmentation.
- Avoid crossing wetlands and minimize stream crossings with new rights-of-way for access roads, pipelines and utilities. Stream crossings should be designed to provide in-stream conditions that allow for and maintain uninterrupted movement and safe passage of fish.
- Develop a habitat restoration management plan that identifies vegetation, soil stabilization, and erosion reduction measures and requires that restoration activities be implemented as soon as possible following facility construction activities.

4.5.4.2 Mitigation Measures for Seismic Surveys

- Identify important, sensitive, or unique habitat and biota in the project vicinity and, to the extent feasible, site and design the survey to minimize or mitigate potential impacts to these resources.

- Use shot hole techniques to eliminate or reduce the need for vibroseis trucks.
- Travel along existing vehicle routes whenever possible to avoid disturbing natural areas.
- Avoid driving on soils that are saturated to avoid creating ruts.
- Reclaim disturbed areas by scarification and reseeding. Obscure two-tracks using rakes or brooms to discourage off-road recreational vehicle use.
- Conduct testing outside of the breeding season for migratory birds and other protected wildlife.
- Avoid seismic testing and vehicle use in and around wetland areas.
- Use helicopters, buggys (vehicles fitted with wide tires) or people on foot to transport receiver line and geophones to remote and sensitive locations to minimize use of trucks.

4.5.4.3 Construction

The impacts from construction required for a carbon sequestration project would be minimized by the use of an existing resource recovery site; i.e., the required facilities for injecting CO_2 and additional wells required for injection and monitoring would be constructed at an existing EOR site or CBM production site. This practice would minimize the incremental impacts from construction of a carbon sequestration project on ecological resources. In addition, a variety of mitigation measures may be implemented to minimize the severity of potential incremental impacts:

- Minimize the size of all disturbed areas.
- Minimize the extent of habitat disturbance by restricting vehicles to access roads and prohibiting foot and vehicle traffic through undisturbed areas.
- Initiate habitat restoration activities in lay-down areas and other temporary construction staging areas immediately after construction activities are completed.
- Schedule construction activities to avoid important periods of wildlife courtship, breeding, nesting, lambing, or calving. Consult with USFWS and other appropriate natural resource agencies to determine the most appropriate schedule.
- Instruct all construction employees to avoid harassment and disturbance of wildlife, especially during reproductive (e.g., courtship, nesting) seasons.
- Establish buffer zones around raptor nests, bat roosts, and biota and habitat of concern.
- Install and maintain noise-reduction devices (e.g., mufflers) on vehicles and construction equipment.
- Implement erosion controls that comply with county, state, and federal standards.
- Reclaim disturbed soil using weed-free native grasses, forbs, and shrubs. Implement reclamation activities as early as possible on disturbed areas.

- Implement dust abatement techniques (e.g., water spraying) on gravel and dirt roads and other unvegetated surfaces to minimize airborne dust. Construction materials and stockpiled soil should be covered if they are a source of fugitive dust.

- Establish and maintain a minimum number of designated fueling areas that include the use of secondary containment, such as drip pans to contain small spills and temporary berms to limit the spread of larger spills.

- Install drip pans under pumps and valve mechanisms used for transfer of fuels or hazardous chemicals.

- Prepare and implement a Spill Management Plan and initiate spill response immediately after a spill.

- Implement a program to minimize the introduction of noxious and invasive weeds

- Limit pesticide use to pesticides that are nonpersistent and immobile.

4.5.4.4 Operation

The potential impacts to biological resources during the operation of a carbon sequestration project would be expected to be fewer and of lesser intensity than during construction. The following mitigation measures would reduce or minimize potential adverse effects on biological resources during operations.

- Turn off all unnecessary lighting at night to minimize disruption of nocturnal behavior of local wildlife.

- Instruct employees, contractors, and site visitors to avoid harassment and disturbance of wildlife, especially during reproductive (e.g., courtship, nesting) seasons.

- As part of the Spill Management Plan, establish and maintain a minimum number of designated fueling areas that include secondary containment, such as the use of drip pans to contain small spills and temporary berms to limit the spread of larger spills.

- Install drip pans under pumps and valve mechanisms used for the transfer of fuels or hazardous chemicals.

- Prepare and implement a Spill Management Plan and initiate spill response immediately after a spill.

- Implement a program to minimize the introduction of noxious and invasive weeds

- Limit pesticide use to pesticides that are nonpersistent and immobile.

- Monitor access road, utility, and pipeline ROWs regularly for invasive species establishment. Weed control measures should be initiated immediately upon evidence of invasive species introduction.

4.5.4.5 Mitigation for Threatened, Endangered, and Sensitive Species

If federally listed species are present in the project vicinity, informal consultation under Section 7 of the ESA would be required before the start of construction and operation of the carbon sequestration project. If a protected species is found to inhabit the project area or adjacent area, and there is a potential for adverse impacts to the species, a Biological Assessment may be required in addition to the assessment of impacts in the site-specific NEPA document for the project. Subsequently, formal consultation with the FWS may be required that would result in a Biological Opinion issued by that agency. The Biological Opinion would specify reasonable and prudent measures and conservation recommendations to minimize impacts on the federally listed species at the site.

A variety of site-specific and species-specific measures may be required to mitigate potential impacts on special status species if present in the project area. Such measures may include:

- Conduct field surveys to verify the presence of the special status species in the project area and especially within individual project footprints. Such field surveys may also indicate the absence of a protected species.

- Avoid siting project facilities or lay-down areas in locations documented to contain or provide important habitat for protected species.

- Consult with federal and state agencies for further mitigation measures to avoid or minimize impacts to protected species on a site-specific basis.

4.5.5 Regional Considerations

Specific impacts to biological resources cannot be fully assessed without knowledge of the location of a proposed project. The type of impacts, the flora and fauna impacted, and to a certain extent the intensity of the potential impacts depend on the state where the project would be implemented and the proposed site within the state. In gross terms, a general description of the flora and fauna that may potentially be impacted can be known from the Ecological Domain and, more specifically, from the Ecological Province in which the project would be located.

A good example of the regional considerations that must be taken into account in siting and assessing the specific potential impacts is the reforestation model project. A reforestation project would not be as successful if sited in the Dry or Polar Domains as it would if sited in the Temperate Domain, primarily because forests in the Dry or Polar Domains are not as vigorous, and therefore would not be as efficient a carbon sink as a forest in the Temperate Domain. In the Temperate Domain, the Appalachian Coalfield Region encompasses the coal-bearing areas of Pennsylvania, Ohio, Maryland, North Carolina, Georgia, West Virginia, Virginia, eastern Kentucky, Tennessee, and Alabama. The Bituminous Coal Basin lies within the Appalachian Plateau physiographic province, extends in a northeast to southwest direction along the Appalachian Mountains, and encompasses the most historically important coal mining areas of the Appalachian Coalfield Region (USACE, 2003).

The *Programmatic Environmental Impact Statement on Mountain Top Mining / Valley Fill* (USACE, 2003) evaluated the impacts of surface coal mining in the Appalachian Coalfield Region, more specifically in the area where Kentucky, West Virginia, and Virginia meet. This area is in two ecological provinces, the Eastern Broadleaf Forest (Oceanic) Province and the Central Appalachian Broadleaf Forest-Coniferous Forest-Meadow Province. These provinces are characterized by temperate deciduous forest dominated by tall broadleaf trees or a mixed oak-pine forest. This would be a good area for reforestation, which would have predominantly beneficial impacts and a minimum of adverse impacts. The land would be replanted with native trees to attempt to restore the area to its pre-disturbance condition. Although there may be long-lasting effects of the mining operations, such as the contours of the mountainous area and the valley fills remaining permanently altered, the area would receive a beneficial impact from the restoration activities.

If a reforestation project would be implemented in another state within the Temperate Domain, it may be located in a different Ecological Province. Although the species of native trees may be different, the impacts would likewise be primarily beneficial; i.e., increased bio diversity, increased erosion control, etc.

Based on the overall locations of geologic formations that could support carbon sequestration, only a limited number of ecological provinces have a high probability of being impacted.

Other potential projects may result in the loss of habitat as described in the sections above. The types of habitat impacted would depend on the specific locations of the projects. Specific habitat types that may be impacted would be identified and described during the development of project-specific NEPA evaluation. Table 4-15 lists these ecological provinces that have suitable conditions for CO_2 sequestration and provides summary information about the biotic resources that may be impacted by potential projects.

Table 4-15. Ecological Provinces with High Probability of Being Impacted by Potential Carbon Sequestration Projects

Domain and Ecological Province*	Predominant Vegetation	Common Fauna	Birds	Representative Protected Species
Temperate Domain				
Eastern Broadleaf Forest (Oceanic)	Temperate deciduous forest dominated by tall broadleaf trees or pine-oak forests (Pine Barrens)	Whitetail deer Black bear Bobcat Squirrels and chipmunks	Turkey Ruffed grouse Bobwhite Mourning dove	Copperbelly water snake American Burying Beetle Virginia Big-eared Bat Gray Bat
Eastern Broadleaf Forest (Continental)	Broadleaf deciduous forests; draught resistant oak-hickory forests	Whitetail deer Squirrels and chipmunks	Blue jays	Copperbelly water snake American Burying Beetle Virginia Big-eared Bat Gray Bat
Prairie Parkland (Temperate)	Forest – Steppe; intermingled prairie, groves and strips of deciduous trees	Both prairie and forest fauna;	Belted kingfisher, spotted sandpiper, green-backed heron, horned lark, eastern meadowlark	Indiana Bat Hind's Emerald Dragonfly
Southeastern Mixed Forest	Medium to tall forests of broadleaf deciduous and needleleaf evergreen trees; Loblolly pine and shortleaf pine	Whitetail deer Cottontail rabbits Fox squirrels	Eastern wild turkey Bobwhite quail Mourning dove	Virginia Big-eared Bat Red-cockaded Woodpecker
Outer Coastal Plains Mixed Forest	Temperate rainforest, evergreens, oaks, and members of the laurel and magnolia families.	Whitetail deer Raccoons opossums Flying squirrels Rabbits	Bobwhite quail Wild turkey Numerous migratory non-game birds species and migratory waterfowl	American Burying Beetle
Dry Domain				
Southwest Plateau and Plains Dry Steppe and Shrub	Arid grasslands – blue gramma and buffalo grasses. Mesquite, oak and Ashe juniper	Mexican ground squirrel Gray fox Whitetail deer Ringtail	Wild turkey Mourning doves Scaled quail Several species of hawks and owls	Golden-cheeked Warbler Black-capped vireo

Domain and Ecological Province*	Predominant Vegetation	Common Fauna	Birds	Representative Protected Species
Chihuahuan Semi-Desert	Thorny shrubs, associated with short grass, e.g. gramma grass. Honey mesquite, cacti Sonoran Desert – Yuccas	Shorttail weasel Black bear Striped skunk Marmot	White-throated sparrow Northern junco Yellow-bellied Sapsucker	
Great Plains-Palouse Dry Steppe	Scattered trees and shrubs – sagebrush and rabbitbrush, buffalo grass, locoweed	Pronghorn antelope Mule deer Whitetail deer	Sage grouse Greater prairie chicken Sharp-tailed grouse Horned lark Western meadowlark Mountain plover	Blackfooted Ferret Lesser Prairie Chicken Piping Plover
Southern Rocky Mountain Steppe-Open Woodland-Coniferous Forest-Alpine Meadow	Alpine tundra Engelmann spruce, subalpine fir Ponderosa pine and Douglas fir Sagebrush	Elk Deer Bighorn sheep Mountain lion Black bear Grizzly bear Moose	Mountain bluebird Red-breasted nuthatch Gray jay Steller's jay	
Intermountain Semi-Desert and Desert	Sagebrush bitterbrush, and shadescale. Woodland zone with pinyon pine and juniper	Mule deer, mountain lion, bobcat Pronghorn antelope Whitetail prairie dog	Burrowing owl Sage sparrow American kestrel Golden eagle	Attwater's greater prairie chicken
Colorado Plateau Semi-Desert	Arid grasslands – sagebrush, cactus, yucca Ponderosa pine Douglas fir	Mule deer Mountain lion Coyote Bobcat Elk	Bushtit Pinyon jay Red-tail hawk Golden eagle Red-shafted flicker	

More detailed information about these, and all the Ecological Provinces is presented in Section 3.5

4.5.6 Summary of Potential Impacts

Table 4-16 provides an overall qualitative assessment of potential impacts to biological resources for each sequestration technology. For the most part, expected impacts to both terrestrial and aquatic habitats and biota would be expected to be negligible to minor (as discussed in 4.5.2), with the exception of potentially beneficial impacts on biological resources from terrestrial reforestation. Implementation of appropriate BMPs and mitigation measures would help minimize potential impacts. Potential impacts to special status species would be negligible, provided that the siting of surface facilities avoids these species or designated critical habitats.

Table 4-16. Potential Impacts of Program Technologies on Biological Resources

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Terrestrial communities	·	O	·	·	·	·	+	·
Aquatic communities	·	·	O	O	·	·	+	·
Wetland communities	·	·	·	·	·	·	·	·
Special status species	·	·	·	·	·	·	·	·

Key: · Negligible Impact, O Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

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4.6 CULTURAL RESOURCES

This section describes the potential impacts to cultural resources (paleontological, archeological and historic resources) that could occur during the implementation of carbon sequestration technologies. The cultural resources that could be affected by sequestration technologies are described in Section 3.6. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.6.1 Impact Considerations

The types of cultural resources that could be affected by a carbon sequestration projects depend on the specific location of the proposed project and its environmental context. Cultural resources that could be affected include paleontological, archaeological and historical resources as well as their contexts. Criteria for assessing the potential for adverse impacts on cultural resources from a potential project are provided below. Impact levels are assessed using the definitions found in Section 4.1.1. Short-term impacts for cultural resources are defined as impacts occurring during the construction timeframe. However, it is important to note that any adverse impacts occurring within the construction timeframe, such as the destruction of previously undiscovered archaeological artifacts, could result in a permanent adverse impact on those resources. Localized impacts for cultural resources are defined as those occurring within the project footprint.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Cause the potential for loss, isolation or substantial alteration of an archaeological resource eligible for listing on the *National Register of Historic Places*.
- Cause the potential for loss, isolation or substantial alteration of a historic site or structure eligible for listing on the *National Register of Historic Places*.
- Introduce visual, audible or atmospheric elements that would adversely affect a historic resource eligible for listing on the *National Register of Historic Places*.
- Cause the potential for loss, isolation or substantial alteration of a American Indian resources, including graves, remain and funerary objects.

4.6.2 Regulatory Framework

In this section, federal laws, executive orders and relevant DOE directives, regulations and/or standards are summarized.

4.6.2.1 Federal Laws and Executive Orders

Several federal laws and related policies have been enacted to protect and manage the Nation's cultural resources. These include:

- National Historic Preservation Act (NHPA) of 1966, as amended (e.g., Sections 101, 106, and 110)
- Antiquities Act of 1906

- Archeological Resources Protection Act (ARPA) of 1979
- Archeological and Historic Preservation Act (AHPA) of 1974
- Native American Graves Protection and Repatriation Act (NAGPRA) of 1990
- American Indian Religious Freedom Act of 1978 (AIRFA)
- Curation of Federally-Owned and Administered Archaeological Collections (36 CFR Part 79)
- Protection and Enhancement of the Cultural Environment (Executive Order No. 11593)
- Indian Sacred Sites (Executive Order No. 13007)
- Consultation and Coordination with Indian Tribal Governments (Executive Order No. 13175)
- Preserve America (Executive Order No. 13287)
- 36 CFR 800, Protection of Historic and Cultural Properties
- 43 CFR Part 10, NAGPRA Regulations
- DOE O 450.1, Environmental Protection Program
- DOE P 141.1, Department of Energy Management of Cultural Resources
- DOE P 454.1, Use of Institutional Controls
- DOE O 430.1B, Real Property Asset Management

In addition, factors that also would be considered include potential land disturbance, contextual intrusion, and access restrictions particularly to American Indian sacred space and traditional use areas. Beyond this, more detailed analysis (including file and field investigations, predictive modeling, direct consultation with tribal representatives, and NRHP eligibility determination) will be done when site-specific or project-specific NEPA documents are developed.

4.6.2.1.1 National Historic Preservation Act (NHPA) of 1966 as amended.

The NHPA is the overarching law concerning the management of cultural resources in the U.S. The law requires that each state appoint a State Historic Preservation Officer (SHPO) to oversee the management of cultural resources that state, and it creates the Advisory Council on Historic Preservation (ACHP), which provides national oversight and dispute resolution. The SHPO is also designated as the repository for all cultural resource information in each state. Section 106 of the NHPA, defines the process for the identification of a cultural resource and the process for determining if a project will adversely affect the resource. The NHPA establishes the processes for consultation among interested parties, the agency conducting the undertaking, and the SHPO, and for government-to-government consultation between U.S. government agencies and American Indian Tribal governments. Section 106 of the NHPA also addresses the appropriate process for mitigating adverse effects. The NHPA applies to federal undertakings and undertakings that are federally permitted or funded. A summary of DOE responsibilities under Section 106 is provided in Table 4-17.

Table 4-17. Summary of the NHPA Section 106 Provisions

(1) Under this section of the NHPA, the DOE is responsible to identify, evaluate, and take into account the effects of all undertakings on historic properties in accordance with the procedures set forth in 36 CFR 800. The ACHP is responsible for providing comments on undertakings that affect historic properties. The SHPO in each state or territory is a significant participant in the Section 106 compliance process by providing comments on efforts to identify, evaluate and treat any effects on historic properties. If an undertaking on DOE lands may affect properties having historic value to a federally recognized Indian tribe, such tribe shall be afforded the opportunity to participate as interested persons during the consultation process defined in 36 CFR 800. Traditional cultural leaders and other American Indians, Native Alaskans, and Native Hawaiians are considered to be interested persons with respect to undertakings that may affect historic properties of significance to such persons.

(2) Failure to take the effects of an undertaking on historic properties into account can result in formal notification from the ACHP to DOE of foreclosure. A notice of foreclosure can be used by litigants against DOE in a manner that can halt or delay critical mission activities.

(3) DOE shall ensure that the efforts to identify, evaluate, and treat historic properties follow the Secretary of the Interior's *Standards and Guidelines for Archeology and Historic Preservation* and are conducted under the supervision of personnel who meet the applicable professional qualifications standards set forth in 36 CFR 61. Disagreements between DOE and the SHPO regarding the eligibility of a property for listing on the NRHP shall be resolved through the procedures at 36 CFR 63.2(d).

(4) Programmatic Agreements (PAs) and Memoranda of Agreement (MOAs) executed pursuant to NHPA Section 106 and 36 CFR 800 are compliance agreements that set forth how DOE will satisfy the responsibilities of Section 106 of the NHPA in the context of a DOE undertaking that will affect an historic property.

Section 110 of the NHPA imposes specific responsibilities on all federal agencies (such as DOE) regarding historic preservation. Section 110 (a)(1) requires that the affirmative preservation responsibilities in Section 110 must be undertaken in a manner consistent with an organization's mission. Such responsibilities include but are not limited to the following:

(1) Establishing an historic preservation program to include the identification, evaluation, and nomination of historic properties to the NRHP in consultation with the ACHP, SHPO, local governments, Indian tribes, Native Alaskans, Native Hawaiian organizations, and the interested public as appropriate.

(2) Prior to acquiring, constructing, or leasing buildings, using available historic properties to the maximum extent feasible.

(3) Documenting historic properties that will be altered or destroyed as a result of the federal action. Such actions must be reviewed in accordance with NHPA Section 106.

(4) In transferring historic properties, ensuring that the significant historic values of the property are appropriately preserved.

(5) Documenting decisions to proceed with agency undertakings that adversely affect historic properties when the they has been unable to reach agreement through execution of an MOA or PA with the ACHP and SHPO.

Section 101(d)(2) of the NHPA provides for the assumption by federally recognized Indian tribes of all or any part of the functions of a SHPO with respect to tribal lands (e.g., all lands within the exterior boundaries of any Indian reservation and all dependent Indian communities). Section 101(d)(6) requires federal activities, in carrying out their Section 106 responsibilities, to consult with federally recognized Indian tribes, Native Alaskans, and Native Hawaiian organizations that attach religious or cultural significance to an historic property. Agencies must consult with federally recognized Indian tribes and Native Hawaiian organizations in the Section 106 process to identify, evaluate, and treat historic properties that have religious or cultural importance to those groups.

4.6.2.1.2 Antiquities Act of 1906, Archeological Resources Protection Act (ARPA) of 1979, Archeological and Historic Preservation Act (AHPA) of 1974

The Antiquities Act of 1906 and ARPA prohibit the excavation, collection, removal, and disturbance of archaeological resources (as defined by ARPA) and objects of antiquity (as referenced in the Antiquities Act) on federally owned property without a permit. Violation of ARPA may result in the assessment of civil or criminal penalties and forfeiture of vehicles and equipment that were used in connection with the violation.

The AHPA specifically provides for the survey and recovery of scientifically significant data that may be irreparably lost as a result of any alteration of the terrain from any federal construction projects, or federally licensed project, activity, or program. Known paleontological resources must also be addressed in any NEPA documentation prepared for actions that might affect or cause irreparable loss or destruction of such resources.

When the DOE finds or is notified in writing by an appropriate authority that its activities might cause irreparable loss or destruction of scientifically significant paleontological resources, the DOE must notify the Secretary of the Interior in writing and provide information concerning the activity in accordance with the AHPA. Such notification may be incorporated as part of the NEPA public review and comment process for the subject activity.

Archaeological resources, objects of antiquity, and significant scientific data from federal installations belong to the installation, except where NAGPRA requires repatriation to a lineal descendant, Indian tribe, or Native Hawaiian organization (See below for a summary of NAGPRA.). Archaeological resources, objects of antiquity, and significant scientific data from nonfederal land belong to the state, territory, or landowner. Such resources from lands used by the DOE but for which fee title is held by another agency are the property of the agency designated as the land manager in the land use instrument (e.g., Public Land Order, Special Use Permit, etc.).

4.6.2.1.3 Native American Graves Protection and Repatriation Act (NAGPRA) of 1990.

The intent of NAGPRA is to identify proper ownership and to ensure the rightful disposition of cultural items that are in federal possession or control. NAGPRA mandates that DOE summarize, inventory, and repatriate cultural items in its possession or control to lineal descendants or to culturally affiliated federally recognized Indian tribes, Native Alaskans, or Native Hawaiian organizations. NAGPRA also requires that certain procedures be followed when there is an intentional excavation of or an inadvertent discovery of cultural items. DOE must ensure compliance with NAGPRA (23 USC 3002) and its implementing regulation (43 CFR Part 10).

DOE may enter into Comprehensive Agreements (CAs) with federally recognized Indian tribes, Native Alaskans, and Native Hawaiian organizations for the purposes of compliance with NAGPRA and 43 CFR Part 10. CAs should establish responsibilities and address all installation land management activities that could result in the intentional excavation or inadvertent discovery of cultural items; establish standard consultation procedures; and provide for the determination of custody, treatment, and disposition of cultural items.

Without a CA, DOE must take reasonable steps to determine whether a planned activity might result in the intentional excavation or inadvertent discovery of cultural items from DOE-owned or controlled lands. When it is determined that cultural items might be encountered, before issuing approval to proceed with the activity, DOE must carry out the consultation procedures and planning requirements at 43 CFR 10.3 and 10.5. Following consultation per 43 CFR 10.5 as part of the intentional excavation or inadvertent discovery of cultural items, a written Plan of Action must be prepared in accordance with 43 CFR 10.5(e).

Such procedures and actions should be coordinated with the requirements of the NHPA and ARPA when such excavations or discoveries might involve historic properties and/or archaeological resources.

If an *inadvertent discovery* of cultural items occurs in connection with an ongoing activity on DOE lands and there is no CA in effect that sets forth agreed-upon procedures for such instances, DOE must comply with 43 CFR 10.4(a-d). Such compliance measures include but are not limited to notifications; cessation of the activity for 30 days in the area of the discovery; protection of the discovery; consultation with Indian tribes, Native Alaskans, or Native Hawaiian organizations affiliated with the discovery in accordance with 43 CFR 10.5; and preparation of a written Plan of Action.

DOE must ensure that all authorizations to carry out activities on federally owned or controlled lands, including leases and permits, require the holder of the authorization to notify DOE immediately upon the inadvertent discovery of cultural items and to protect such discoveries until applicable compliance procedures are satisfied. DOE also must ensure that intentional excavation and response to any inadvertent discovery of NAGPRA cultural items are carried out in compliance with all applicable statutory and regulatory requirements of NAGPRA, ARPA, and NHPA. Each statute mandates compliance with independent requirements. Compliance with one statutory requirement, therefore, may not satisfy other applicable requirements.

All activities carried out to comply with NAGPRA and 43 CFR 10 must occur only with federally recognized Indian tribes, Native Alaskans, and Native Hawaiian organizations, and lineal descendants as defined and provided for by NAGPRA.

4.6.2.1.4 American Indian Religious Freedom Act (AIRFA) of 1978 and Executive Order No. 13007 Indian Sacred Sites.

Under AIRFA and EO 13007, DOE must develop and implement procedures to protect and preserve the American Indian, Eskimo, Aleut, and Native Hawaiian right of freedom to believe, express, and exercise these peoples' traditional religions, including, but not limited to, access to sacred sites, use and possession of sacred objects, and freedom to worship through ceremonials and traditional rites. DOE must consult with Indian tribes and Native Hawaiians to identify sacred sites that are necessary to the exercise of traditional religions and must provide access to DOE installations for Indian tribe, Native Alaskan, and Native Hawaiian practice of traditional religions, rights, and ceremonies. DOE may impose reasonable terms, conditions, and restrictions on access to such sites when it is deemed it necessary for the protection of personal health and safety, or to avoid interference with the Agency mission, or for other reasons of national security.

DOE must maintain the confidentiality of sacred site locations. The DOE is required to avoid adversely affecting the physical integrity of sacred sites and must establish procedures to ensure reasonable notice is provided to federally recognized Indian tribes, Native Alaskans, and Native Hawaiian organizations when proposed actions or land management policies and practices may restrict future access to or ceremonial use of or adversely affect the physical integrity of sacred sites. If a sacred site might be affected by DOE land management policies or practices, then the DOE must also ensure that the compliance requirements of the NHPA are met if the sacred site meets the NHPA definition of an historic property.

4.6.2.1.5 Curation of Federally Owned and Administered Archeological Collections (36 CFR 79)

DOE must ensure that all "collections," as defined in 36 CFR 79.4(a), are processed, maintained, and curated in accordance with the requirements of 36 CFR Part 79. However, NAGPRA cultural items and human remains in DOE's possession and control must be disposed of in a manner consistent with the requirements of NAGPRA and 43 CFR Part 10. DOE archaeological collections may be processed, maintained, and curated on and by DOE or another federal agency, state agency, or other outside institution or nongovernmental organization, in cooperative repositories maintained by or on behalf of multiple agencies, or in other facilities, under contract, cooperative agreement, or other formal funding and administrative arrangement provided the standards of 36 CFR Part 79 are met.

4.6.2.1.6 Protection and Enhancement of the Cultural Environment (Executive Order. No. 11593)

This Executive Order requires federal agencies to initiate measures to preserve, restore and maintain federally owned sites, structures and objects of historical, architectural or archaeological significance, and in consultation with the ACHP to institute procedures to assure that federal plans and programs contribute to the preservation and enhancement of non-federally owned sites, structures and objects of historical, architectural or archaeological significance. Federal agencies must inventory their cultural resources and to record, to professional standards, any cultural resource that may be altered or destroyed.

4.6.2.1.7 Consultation and Coordination with Indian Tribal Governments (Executive Order No. 13175)

This Executive Order requires federal agencies to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen government-to-government relations with Indian tribes.

4.6.2.1.8 Preserve America (Executive Order No. 13287)

This Executive Order seeks to enhance federal stewardship of historic properties, promote the benefits of historic preservation, and improve federal agency planning and accountability. Federal agencies such as DOE must maximize their efforts to integrate the policies procedures and practices of the NHPA and this order into their program activities in order to advance historic preservation objectives while efficiently and effectively pursuing their mission.

4.6.2.2 DOE Directives, Policy and Guidance

In addition to the above, there are a number of DOE directives, regulations and/or standards that are relevant to protecting and managing the Agency’s cultural resources. These include:

- DOE O 450.1, Environmental Protection Program
- DOE P 141.1, DOE Management of Cultural Resources
- DOE G 450.1-3, Environmental Guidelines for Development of Cultural Resource Management Plans
- DOE P 454.1, Use of Institutional Controls
- DOE O 430.1B, Real Property Asset Management

4.6.2.2.1 DOE O 450.1, Environmental Protection Program

This Order requires implementation of sound stewardship practices to protect natural and cultural resources impacted by DOE operations, and allow the Agency to meet or exceed compliance with applicable environmental, public health, and resource protection requirements in a cost-effective way. This objective is accomplished through the implementation of Environmental Management Systems

(EMSs) as part of Integrated Safety Management Systems (ISMSs) that are established by DOE facilities to comply with DOE P 450.5, *Safety Management System Policy.* DOE Order 450.1 specifically notes that cultural resources should be considered in EMSs.

4.6.2.2.2 DOE P 141.1, Department of Energy Management of Cultural Resources

The purpose of this policy is ensure that cultural resource management is integrated into DOE's missions and activities, and to raise the level of awareness and accountability among DOE contractors concerning the importance of DOE's cultural resource-related legal and trust responsibilities. Specifically cited are DOE's responsibilities under all of the above referenced requirements (viz., NHPA,AHPA, ARPA, NAGPRA, and Executive Orders 11593, 13175 and 13007) as well as the Secretary of the Interior's *Standards and Guidelines for Archeology and Historic Preservation, Standards and Guidelines for Federal Agency Historic Preservation Programs*, and *Standards for Rehabilitation* and *Guidelines for Rehabilitating Historic Buildings.* The policy states that the DOE will uphold these laws by preserving, protecting and perpetuating cultural resources for future generations in a spirit of stewardship, and will implement management accountability for compliance with all applicable laws, treaties, orders and guidance. Finally, responsible DOE managers are required to develop, implement and periodically review a Cultural Resources Management Plan at all DOE facilities, and that Lead Program Secretarial Officers (LPSOs) and Cognizant Secretarial Officers (CSOs) will carry out these efforts, including integration of cultural resource concerns into program and project planning, for sites and facilities for which they have landlord responsibilities.

4.6.2.2.3 DOE G 450.1-3, Environmental Guidelines for Development of Cultural Resource Management Plans

The purpose of this document is to provide guidelines to DOE field managers who are responsible for the development of an individual Cultural Resource Management Plan (CRMP) for each DOE facility and program. The guidelines are developed as a planning vehicle for ensuring that each DOE facility and program complies with laws, regulations, Executive Orders and DOE directives governing the management of cultural resources, and that the cultural resource planning process is integrated into compliance actions driven by other environmental laws such as NEPA. The guide provides a format for the preparation of CRMPs as well as recommendations, alternatives and approaches for meeting CRMP requirements.

4.6.2.2.4 DOE P 454.1, Use of Institutional Controls

This policy specifies how DOE will use institutional controls to manage its resources, facilities and properties. The policy specifically notes that DOE uses a wide range of such controls to manage and protect cultural resources under its jurisdiction. Institutional controls may include administrative or legal controls, physical barriers or markers, and methods to preserve information and data.

4.6.2.2.5 DOE O 430.1B, Real Property Asset Management

This order describes DOE's system for establishing a "corporate, holistic and performance-based" approach to real property life-cycle asset management. It requires that cultural asset management and historic preservation be considered in land use and disposition plans.

4.6.3 Generalized Siting and Operational Impacts of Technologies

4.6.3.1 Post-combustion Capture

Post-combustion capture projects would be retrofitted to existing, or added to proposed, fossil fuel combustion facilities or comparable industrial processes. Generally, the addition of a CO_2 capture process to an existing facility would have negligible impacts to cultural resources or their context, unless they were encountered (and left in place) during the initial development of the existing facility or a site file and/or field investigation was not adequately done when the existing facility was initially developed. An exception might be if the new process required a significant expansion of the facility property or would otherwise introduce features that would adversely affect cultural resources or their context.

A post-combustion capture project would likely be sited at an existing fossil-fueled power plant or other compatible industrial facility. Such facilities generally provide adequate property for expansion within the site boundary. However, if a CO_2 capture project created a need to acquire additional land for the facility, an assessment of site-specific impacts on cultural resources would be required. In the event that a capture process would be associated with a proposed new industrial facility, the site-specific impacts on cultural resources for the project would be encompassed within the environmental review for the new facility.

4.6.3.2 CO_2 Compression and Transport

CO_2 compression facilities would require a small footprint of land, most likely located in proximity to a CO_2 capture process on the property of an existing power plant or comparable industrial facility. Generally, the addition of CO_2 compression facilities to an existing industrial site would not likely result in significant adverse impacts to cultural resources and would have a negligible, if any, impact on their context. Exceptions would occur if additional site acquisition or significant expansion of the facility property were required, and/or if it would otherwise introduce features that would adversely affect cultural resources and their context.

Although smaller scale field validation projects may allow for transportation of CO_2 to a sequestration site via compressed gas container trucks or rail cars, it is assumed that a cost-effective commercial application would require conveyance via compressed gas pipelines. Therefore, the principal aspect of a CO_2 compression and transport project that would affect cultural resources if there were a potential need for easements and rights-of-way for CO_2 pipelines and booster stations. Where practicable, impacts on cultural resources can be minimized by co-utilizing easements already in use for other utility pipelines and power transmission lines. Otherwise, new easements must be established, in which case a survey would have to be performed of the utility corridor to determine potential site-specific impacts on cultural resources.

Although it is assumed that proper planning and study would be conducted on areas affected by construction of compression and transport facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.3.3 Sequestration in Coal Seams

Siting for coal seam sequestration projects would depend on the identification of suitable coal seams within sufficient proximity of potential CO_2 sources. Therefore, coal seams closest to existing fossil fuel-fired power plants or other CO_2 sources would be the optimal candidates for commercial application initially. Hence, before selecting a suitable location for a coal seam sequestration project, an assessment of site-specific impacts on cultural resources would be required.

Clearing, grading, runoff and erosion, along with construction activities associated with drill pads, ancillary facilities, access roads and pipelines could result in direct alteration or destruction of cultural resources. The significance of the potential impact to any cultural resources cannot be known without proper investigation and analysis at each specific site. In addition, clearing adjacent to a proposed project site or within access road ROW may also be required and this would further raise the prospect of impacts to cultural resources.

Fugitive dust generated during clearing, grading, and construction activities could impact cultural resources or their context in the vicinity of the project area. Fugitive dust generation may be relatively high at sites located in the more arid ecological provinces. In these instances, most impacts are expected to be short term, although the potentially abrasive nature of fugitive dust may impact susceptible cultural resources (e.g., fragile structures, rock art, etc.).

Construction equipment would need to be refueled and some hazardous materials or wastes, such as waste paints and degreasing agents, may be generated. Accidental spill of fuel, lubricating oils or hazardous materials could result in damage to cultural resources at the project site. While these impacts would be expected to be small and localized, they also could significantly alter and/or damage some cultural resources. With the removal of contaminated soil, residual effects would be minimized.

Coal seam carbon sequestration model projects could be sited in an area with surface water features such as streams or rivers, lakes, ponds, and wetlands. Because of the importance of water to human and other animal life, it is possible there may be increased occurrences of cultural resources near these water features, especially if they are generally in the same location now as during historic, archaeological and paleontological periods. The layout of the project would be flexible enough that surface water features could be avoided in siting drill pads and ancillary facilities, however, the situation could occur that access roads or pipelines may have to cross a stream, river or a wetland.

The types of cultural resources that could be affected would be a function of the site-specific environmental conditions present at the facility location. Clearing, grading, erosion and runoff, and construction activities may result in direct disturbance or reduction of cultural resources that may be present within construction footprint, including access roads and pipeline. Compliance with the applicable requirements would limit the likelihood of construction occurring in or impacting cultural resources.

Although it is assumed that proper planning and study would be conducted on areas affected by construction of coal seam sequestration facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.3.4 Sequestration in Depleted Oil and Gas Reserves

Sequestration in depleted oil and gas reserves is similar to sequestration under the coal seam concept. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation.

During construction, adverse cultural resource effects could occur from activities such as the modification of drainage patterns, erosion and runoff, fugitive dust, removal of vegetation cover, exposure of cultural resources to contaminants, and modification of the subsurface strata. Site clearing and grading, along with construction of drill pads, ancillary facilities, pipelines, and access roads could disturb, dramatically alter or destroy existing cultural resources in the disturbed portions of the project area.

Fugitive dust generated during clearing, grading, and construction activities could impact cultural resources or their context in the vicinity of the project area. Fugitive dust generation may be relatively high at sites located in the more arid ecological provinces. In these instances, most impacts are expected to short-term, although the potentially abrasive nature of fugitive dust may impact susceptible cultural resources (e.g., fragile structures, rock art, etc.).

Construction equipment would need to be refueled and some hazardous materials or wastes, such as waste paints and degreasing agents, may be generated. Accidental spill of fuel, lubricating oils or hazardous materials could result in damage to cultural resources at the project site. While these impacts would be expected to be small and localized, they also could significantly alter and/or damage some cultural resources. With the removal of contaminated soil, residual effects would be minimized.

Although it is assumed that proper planning and study would be conducted on areas affected by construction of EOR sequestration facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.3.5 Sequestration in Saline Formations

Sequestration in a saline geologic formation is similar to sequestration under the coal seam concept. Both types of projects consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation. The construction phase would consist of drilling wells into a saline geologic formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, methane, and water.

During construction, adverse cultural resource effects could occur from activities such as the modification of drainage patterns, erosion and runoff, fugitive dust, removal of vegetation cover, exposure of cultural resources to contaminants and modification of the subsurface strata. Site clearing and grading, along with construction of drill pads, ancillary facilities, pipelines, and access roads could disturb, dramatically alter or destroy existing cultural resources in the disturbed portions of the project area.

Fugitive dust generated during clearing, grading, and construction activities could impact cultural resources or their context in the vicinity of the project area. Fugitive dust generation may be relatively high at sites located in the more arid ecological provinces. In these instances, most impacts are expected to short-term, although the potentially abrasive nature of fugitive dust may impact susceptible cultural resources (e.g., fragile structures, rock art, etc.).

Construction equipment would need to be refueled and some hazardous materials or wastes, such as waste paints and degreasing agents, may be generated. Accidental spill of fuel, lubricating oils or hazardous materials could result in damage to cultural resources at the project site. While these impacts would be expected to be small and localized, they also could significantly alter and/or damage some cultural resources. With the removal of contaminated soil, residual effects would be minimized.

Although it is assumed that proper planning and study would be conducted on areas affected by construction of saline formation sequestration facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.3.6 Sequestration in Basalt Formations

Sequestration in a basalt formation is similar to sequestration under the coal seam concept. Both types of projects consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation. The construction phase would consist of drilling wells into a basalt formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, methane, and water.

During construction, adverse cultural resource effects could occur from activities such as the modification of drainage patterns, erosion and runoff, fugitive dust, removal of vegetation cover, exposure of cultural resources to contaminants and modification of the subsurface strata. Site clearing and grading, along with construction of drill pads, ancillary facilities, pipelines, and access roads could disturb, dramatically alter or destroy existing cultural resources in the disturbed portions of the project area.

Fugitive dust generated during clearing, grading, and construction activities could impact cultural resources or their context in the vicinity of the project area. Fugitive dust generation may be relatively high at sites located in the more arid ecological provinces. In these instances, most impacts are expected to short-term, although the potentially abrasive nature of fugitive dust may impact susceptible cultural resources (e.g., fragile structures, rock art, etc.).

Construction equipment would need to be refueled and some hazardous materials or wastes, such as waste paints and degreasing agents, may be generated. Accidental spill of fuel, lubricating oils or hazardous materials could result in damage to cultural resources at the project site. While these impacts would be expected to be small and localized, they also could significantly alter and/or damage some cultural resources. With the removal of contaminated soil, residual effects would be minimized.

Although it is assumed that proper planning and study would be conducted on areas affected by construction of basalt formation sequestration facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.3.7 Terrestrial Sequestration - Reforestation

Terrestrial sequestration projects generally would entail efforts aimed at reforesting and amending landscapes degraded by previous mining operations through the establishment of shrubs and trees that will convert CO_2 into biomass. The cycle of typical site activities would include preparation (clearing, disking, soil amendment, applying herbicides), planting and seeding (hand or mechanical), and maintenance (thinning, harvesting, fertilization, monitoring, and security). Because of the present degraded character of these landscapes, it is anticipated that any cultural resources that were present would not be impacted further. Therefore, terrestrial sequestration is expected to have a negligible impact on cultural resources. Regardless of this assumption, all applicable laws, regulations, policies, standards and directives must be followed. In addition, potential impacts associated with American Indian sacred space and traditional use areas, contextual intrusion, and land disturbance should be considered.

> Because DOE reforestation projects would be focused on already degraded areas, it is likely that any cultural resources that may have been present would not be impacted further by future activities.

4.6.3.8 Co-Sequestration of H_2S and CO_2

Potential short-term (i.e., the construction stage) and long-term impacts related to the sequestering of both H_2S and CO_2 would be similar to the potential impacts for sequestering in coal seams, oil and gas fields, or saline formations. For the most part, surface facilities would be the same, with the exception that materials used for compressing and transporting the gas would have to resist the corrosive nature of H_2S. Although it is assumed that proper planning and study would be conducted on areas affected by construction of co-sequestration facilities, there is some potential for accidental and minor adverse impacts to archeological and buried American Indian artifacts during the construction phase.

4.6.4 Mitigation of Potential Adverse Impacts

Cultural resources could be encountered on lands utilized in association with carbon sequestration projects. These would be generally identified and assessed on a project-specific basis. Because fossils only appear in sedimentary rock formations, this is an efficient initial screen as to the potential for the presence of fossils in a project area. Many states maintain a database or repository for information on past paleontological, archaeological and historic resources either through the SHPO or through a designated repository, such as a university. If there would be a strong potential for cultural resources to be present in a project area, a survey would be required. The following measures are recommended to mitigate the adverse impacts of Carbon Sequestration technologies on cultural resources:

4.6.4.1 Project Planning and Design

- If the project would be located at an existing industrial facility, determine whether adequate, suitable land area is available to accommodate new facilities without affecting cultural resources. If the project will require the acquisition of new sites for facilities, areas should be avoided that may result in the disturbance or destruction of cultural resources or their context. The presence of archaeological sites and historic properties in the area of potential effect should be determined on the basis of an investigation of recorded sites and properties in the area and/or an archaeological survey. The SHPO is the primary repository for this Cultural Resource information.

- Archaeological sites and historic properties present in the area of potential effect should be reviewed to determine whether they meet the criteria of eligibility for listing on the National Register of Historic Places (NRHP). Cultural resources listed on or eligible for listing on the NRHP are considered "significant" resources.

- Consultation with American Indian governments should be done early in the planning process to identify issues and areas of concern. Aside from the fact that this consultation is required under the NHPA, consultation is necessary to establish whether the project is likely to disturb traditional cultural properties, affect access rights to particular locations, disrupt traditional cultural practices, and/or visually impact areas important to the tribe(s).

- If cultural resources are present at the site, or if areas with a high potential to contain cultural material have been identified, a CRMP should be developed. This plan should address mitigation activities to be implemented for cultural resources found at the site. Mitigation options include avoidance of the area, archaeological survey and excavation (as warranted), and monitoring. If an area exhibits a high potential, but no artifacts are observed during an archaeological survey, monitoring by a qualified archaeologist could be required during all excavation and earthmoving in the high-potential area. A report should be prepared documenting these activities. The CRMP also should (1) establish a monitoring program, (2) identify measures to prevent potential looting/vandalism or erosion impacts, and (3) address the education of workers and the public to make them aware of the consequences of unauthorized collection of artifacts and destruction of property on public land.

- If a project is proposed to be located on lands controlled by Federal or state agencies, confer with the appropriate representatives of the respective landowner to determine potential limitations, restrictions and procedures that would be applicable to the project.

- Determine whether rights-of-way will be required for pipeline corridors, access roads, or other facilities. Identify and assess the occurrence of cultural resources that may be present to accommodate additional pipelines or access roads in the proposed transmission corridor.

4.6.4.2 Construction

- Depending on the specific location, the construction necessary for development would have the greatest potential to impact cultural resources because of the increased ground disturbance during this phase. The footprint of land area disturbance required for a proposed project should be minimized. Consultation pursuant to Section 106 of the NHPA would minimize potential effects on cultural resources.

- Vehicular traffic and ground clearing (such as the removal of vegetation cover) could affect cultural resources directly or indirectly through compacting soils, potentially crushing artifacts, disturbing historic features (e.g., trails), displacing cultural material from its original context, and soil erosion. These activities might also impact areas of interest to American Indians, such as sacred areas or areas used for harvesting traditional resources, such as medicinal plants. The creation of access roads could also modify drainage patterns and possibly result in impacts caused by erosion. Erosion has the potential to alter fossil beds and archaeological artifacts, including the possible separation of a collection of fossils and artifacts. Site investigations and implementation of a CRMP would mitigate these potential impacts.

- American Indian concerns should be identified through direct consultation with tribal representatives and field visits with tribal religious specialists during site-specific tiered NEPA documents. Contacts would be identified by reference to the ethnographic literature, by state and national pantribal organizations, and by agency and academic anthropologists.

4.6.4.3 Operation

Fewer impacts on cultural resources are likely from the operation of a carbon sequestration project than from its construction. Impacts associated with operation are possible, however, because of the improved access to the area and the presence of workers and the public. Throughout the period of facility operations, diligence would have to be exercised with respect to archaeological sites, traditional cultural and historic properties, and paleontological resources. Facility operations will be conducted in compliance with applicable cultural resource laws, regulations, policies and procedures, including DOE directives.

4.6.5 Summary of Potential Impacts

Table 4-18 provides an overall qualitative assessment of potential impacts to cultural resources for each sequestration technology. In general, impacts on historical resources are expected to be negligible, because these resources can be avoided most effectively during project siting. Potential impacts on archaeological and American Indian resources would be related to the potential existence of resources on or beneath proposed sites and the extent of land area to be disturbed for site preparation and construction of drill pads, ancillary facilities, pipelines, and access roads. These impacts are anticipated to be negligible to minor, because most projects would be located in areas that have already been disturbed for coal, oil, and gas extraction. Furthermore, impacts can be mitigated appropriately through the performance of site-specific file investigations, consultations, field surveys, and data recovery where necessary. Terrestrial reforestation projects are expected to occur on lands damaged during prior mining operations, where they would be expected to have negligible impacts on cultural resources. Post-combustion capture projects are expected to have negligible impacts on cultural resources, because they would be located on the properties of existing fossil-fueled

> Potential impacts to archeological resources from geologic sequestration projects are anticipated to be negligible to minor, because most projects would be located in areas already disturbed for coal, oil and gas extraction.

plants or would be included in the site-specific investigations for new facilities.

Table 4-18. Potential Impacts of Program Technologies on Cultural Resources

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Archaeological resources	·	○	○	○	○	○	·	○
Historic resources	·	·	·	·	·	·	·	·
American Indian resources	·	○	○	○	○	○	·	○

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.7 AESTHETIC AND SCENIC RESOURCES

This section describes the potential impacts to aesthetic and scenic resources that could occur during the implementation of carbon sequestration technologies. The aesthetic and scenic resources that could be affected by sequestration technologies are described in Section 3.7. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.7.1 Impact Considerations

Aesthetic and scenic resources that may be affected by a sequestration project include landforms, bodies of water, vegetation, and structures. Some of these resources have been listed in the National Register of Historic Places by the National Park Service and designated as National Historic Sites, National Parks, National Preserves, National Rivers, National Seashores, National Wild and Scenic Rivers, or other similar designation. Potential impacts on aesthetic and scenic resources have been assessed using the general criteria outlined below and the definitions provided in Section 4.1.1. Short-term impacts for aesthetic and scenic resources are defined as impacts occurring during the construction timeframe. Localized impacts for aesthetic and scenic resources are defined as those that could occur within the visual range of the project footprint.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would: cause the potential for loss, isolation or substantial alteration of a American Indian resources, including graves, remain and funerary objects.

The types of aesthetic and scenic resources that could be affected by carbon sequestration projects depend on the assessment of the area's scenic values, the size of the area, and the specific location of the proposed project. The Bureau of Land Management (BLM) has developed a Visual Resource Management (VRM) system to identify and evaluate the scenic value of public lands. The system also provides a way to analyze potential visual impacts of proposed projects and activities, and it may be useful for evaluating impacts on aesthetic resources during site selection for potential carbon sequestration projects. The BLM is responsible for managing 262 million acres of land--about one-eighth of the land in the U.S.--and about 300 million additional acres of subsurface mineral resources. Subsequently, many carbon sequestration projects could potentially be influenced by BLM guidelines and regulations.

In the VRM system, the BLM applies visual design techniques to ensure that surface-disturbing activities are in harmony with their surroundings (BLM, 2005). The VRM system first inventories the visual quality of scenic resources through the rating of key factors (landform, vegetation, water, color, influence of adjacent scenery, scarcity, and cultural modifications) and then assigns the area to a management class with established objectives (BLM, 2005a). "The process involves rating the visual appeal of a tract of land, measuring public concern for scenic quality, and determining whether the tract of land is visible from travel routes or observation points" (BLM, 2005). The BLM then can determine whether the potential project would meet the established management objectives for the area or if design changes/modifications need to be made. It can also identify measures to mitigate potential visual impacts (BLM, 2005b). VRM classes and objectives are listed in Table 4-19.

Table 4-19. Bureau of Land Management Visual Resource Management Classes

Class	Management Objective
Class I	To preserve the existing character of the landscape. The level of change to the characteristic landscape should be low and must not attract attention.
Class II	To retain the existing character of the landscape. The level of change to the characteristic landscape should be low.
Class III	To partially retain the existing character of the landscape. The level of change to the characteristic landscape should be moderate.
Class IV	To provide for management activities which require major modifications of the existing character of the landscape. The level of change to the characteristic landscape can be high.

Source: BLM, 2005.

4.7.2 Regulatory Framework

Carbon sequestration projects would need to consider applicable federal, state, and local laws and regulations concerned with aesthetic and scenic resources. Major federal laws and regulations are listed in Table 4-20.

Table 4-20. Major Laws and Regulatory Requirements for Aesthetic and Scenic Resources

Law/Regulation	Key Elements
Wild and Scenic Rivers Act of 1968, as amended (16 USC § 1271).	The Act establishes a National Wild and Scenic Rivers System and prescribes the methods and standards through which additional rivers may be identified and added to the system. Rivers are classified as wild, scenic, or recreational, and hunting and fishing are permitted in components of the system under applicable Federal and State laws. The Act authorized the Secretary of the Interior and the Secretary of Agriculture to study areas and submit proposals to the President and Congress for addition to the system. It describes procedures and limitations for control of lands in Federally administered components of the system and for dealing with disposition of lands and minerals under Federal ownership.
Noise Control Act of 1972 (42 USC § 4901)	This Act authorizes the establishment of Federal noise emissions standards for products distributed in commerce and coordinates Federal research efforts in noise control.

4.7.3 Generalized Siting and Operational Impacts of Technologies

4.7.3.1 Post-combustion Capture

It is assumed that post-combustion capture projects would be retrofitted to an existing industrial facility where CO_2 is formed as a product of fossil fuel combustion. Such projects are likely to be located in an industrial site adjacent to an existing power plant or other industrial facility. Utility hookups and access roads are expected to already exist. While the addition of this technology may cause some increase in personnel (traffic flow) and waste generation, the visual impacts of such projects are expected to be negligible (little or no change) because of the likely industrialized location of post-combustion capture projects.

4.7.3.2 CO_2 Compression and Transport

As described for the model project in Section 2.5, two options were considered for transporting CO_2 to a sequestration site. In the first option, CO_2 from flue gas or another industrial source would be transported by compressed gas pipeline to a sequestration site. In the second, liquid CO_2 would be transported to the site via commercial refrigerated tank trucks.

The use of a compressed gas pipeline would require transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new rights-of-way would need to be cleared. This clearing would result in potential moderate adverse impacts (long-term and localized) on aesthetic and scenic resources. Such impacts may range from negligible to moderate depending upon the existing characteristics of the proposed corridor.

The option of transporting CO_2 to a sequestration site via tank trucks is expected to have negligible impact on aesthetic and scenic resources. The principal impacts would result from the need for CO_2 storage tanks at the compression site and the increase in truck traffic between the capture site and the sequestration site. Because the compression facilities and storage tanks would most likely be located on the property of a power plant or other industrial facility (CO_2 source), aesthetic and scenic impacts would be negligible. The impact on scenic resources from additional truck traffic from the capture facility to the sequestration site could be minimized by selecting appropriate truck routes that avoid sensitive resources.

4.7.3.3 Sequestration in Coal Seams

Siting for coal seam sequestration projects would depend on the identification of suitable coal seams within sufficient proximity of potential CO_2 sources to enable cost-effective conveyance. As described in Section 2.5, sequestration projects would most likely be located in close proximity to an existing power plant or other industrial facility (CO_2 source). Therefore, unmineable coal seams located near existing fossil fuel-fired power plants or other CO_2 sources would be optimal candidates for commercial application initially. Exploration for new coals seams suitable for ECBM and CO_2 sequestration is anticipated. Hence, future projects may be located in areas that have previously been undisturbed, which may in turn cause degradation to currently pristine areas.

Site preparation activities would include access road development and clearing of ground cover. Aboveground structures would likely consist of well equipment, a small mobile trailer, and storage tanks to store waste water recovered during CBM recovery. Additionally, the use of a compressed gas pipeline would require transmission corridors. If existing rights-of-way were not available or accessible between the capture facility and the sequestration site, new easements would be required. The need for new rights-of-way to be cleared of extensive vegetation and remain accessible for maintenance vehicles would result in potential moderate adverse impacts on aesthetic and scenic resources as described in Section 4.7.2.2.

Short-term aesthetic impacts during construction of the surface facilities would be minor (short-term and localized), relating to the activities necessary to clear the site, and include the exhaust emissions, fugitive dust, and noise from construction equipment. Long-term aesthetic impacts from operations would be negligible (not perceptible) to minor (localized) assuming that surface facilities would not be located in important scenic and natural areas.

4.7.3.4 Sequestration in Depleted Oil and Gas Reserves

There are many existing commercial-sized projects of geologic sequestration in oil reservoirs as part of EOR from which the following information is based. Siting for these projects would depend on the identification of suitable, existing oil reservoirs within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance. Impacts during construction and operation would be similar to those for coal seam sequestration projects (Section 4.7.3.3).

4.7.3.5 Sequestration in Saline Formations

Siting for carbon sequestration projects in saline formations would depend on the identification of suitable formations within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance. Therefore, saline formations located near existing fossil fuel-fired power plants or other CO_2 sources would be optimal candidates for commercial application initially. Impacts during construction and operation would be similar to those for coal seam sequestration projects (Section 4.7.3.3).

4.7.3.6 Sequestration in Basalt Formations

Siting for carbon sequestration projects in basalt formations would depend on the identification of suitable formations within sufficient proximity of existing power plants or other industrial facilities (CO_2 sources) to enable cost-effective conveyance. Therefore, basalt formations located near existing fossil fuel-fired power plants or other CO_2 sources would be optimal candidates for commercial application initially. Impacts during construction and operation would be similar to those for coal seam sequestration projects (Section 4.7.3.3).

4.7.3.7 Terrestrial Sequestration - Reforestation

The enhancement of terrestrial carbon sequestration through reforestation projects involving landscapes that have been degraded from the extraction of fossil fuels would have a net beneficial impact (long-term restoration) on aesthetic and scenic resources. The planting of trees in these areas would not only provide the potential for removing CO_2 from the atmosphere, but reforestation would improve the visual quality of the areas by restoring the landscape, reducing soil erosion and sedimentation in surface waters, and increasing potential wildlife habitat.

4.7.3.8 Co-Sequestration of H_2S and CO_2

Co-sequestration of H_2S and CO_2 would be similar to sequestration of CO_2 in coal seams, oil and gas reserves and saline formations. The facilities and infrastructure would be the same, however, different materials for pumps, compressors, and pipelines would be used to guard against the corrosive nature of the sour gas. As with the aforementioned model projects, short-term aesthetic impacts during construction of the surface facilities would be minor (short-term and localized), relating to the activities necessary to clear the site and including the exhaust emissions, fugitive dust, and noise from construction equipment. Long-term aesthetic impacts from operations would be negligible to minor assuming that surface facilities would not be located in important scenic and natural areas.

4.7.4 Mitigation of Potential Adverse Impacts

The following BMPs are recommended to mitigate potential adverse impacts of sequestration technologies on aesthetic and scenic resources. The BMPs are protective, economically feasible measures that can be developed and implemented, on a site-specific or project-specific basis, during the project planning and design, construction, and operation phases. These measures are aimed at reducing, preventing, or mitigating adverse environmental impacts to the aesthetic and scenic quality of the lands.

> The need for cleared and maintained pipeline corridors for CO_2 transmission may result in the most extensive impacts on scenic resources. These impacts could be avoided by using existing corridors where feasible.

4.7.4.1 Project Planning and Design

- Use established easements and existing rights-of-way wherever feasible to avoid the need for clearing and maintaining new corridors for CO_2 transmission.

- Maintain the integrity of topographic units by locating projects away from prominent topographic features and designing projects to blend with topographic forms in shape and placement (BLM, 2005b).

- Minimize the number of visible structures (BLM, 2005b). Great effort should be taken in locating structures and sites away from highly scenic areas, prominent features, or other highly visible areas (e.g., ridgetops) in order to mitigate visual impacts.

- Minimize the contrast between structures and natural surroundings by using earthtone paints and stains, using cor-ten steel (self-weathering), treating wood for self-weathering, using natural stone surfaces, burying part or all of the structure, and selecting paint finishes with low levels for reflectivity (i.e., flat or semi-gloss) (BLM, 2005b).

- Redesign structures that do not blend or fit with the viewscape by using rustic designs and native building materials, using natural-appearing forms to complement landscape character (use special designs only as a last resort), and relocating the structure, if possible (BLM, 2005b).

- Plan road systems to avoid unnecessary surface disturbance and construction costs. Use existing roads whenever possible.

- Plan and design the smallest footprint possible. Reduce the size of disturbed area to the minimum that is needed for the site.

- Involve and inform the public about the visual site design elements of the proposed project. Possible approaches include conducting public information meetings and disseminating information concerning project features (BLM, 2004).

- Avoid placing commercial symbols (such as logos), trademarks, messages, advertising messages, and billboards at the site or on ancillary structures or equipment (BLM, 2004).

- Avoid designs that require security lighting. If such lighting is necessary, use motion detectors to activate lights (BLM, 2004).

- Provide workers with project orientation to increase their understanding of the sensitivity of the environment and lands on which the project is located (NPS, 2004). Ensure that all workers are trained in how to handle hazardous materials spills that may occur on site and the ecological and aesthetic damage that they may cause.

4.7.4.2 Construction

- Reduce the size of cut and fill slope by avoiding steep slopes, changing the road width and grade, changing the road alignment to follow existing grades, and prohibiting the dumping of excess material on downhill slopes (BLM, 2005b). Roads located along ridgetops may be less visible than those located on the ridge face due to increased cut, fill, and sidecast material.

- Reduce earthwork contrasts by rounding and/or warping slopes; retaining rocks and trees; toning down freshly broken rock faces with asphalt emulsion spray or with gray point; adding topsoil, mulch, or hydromulch; shaping cuts and fills to appear as natural forms; cutting rock areas so forms are irregular; designing projects to take advantage of natural screens such as vegetation and land forms; and seeding of cuts and fills (BLM, 2005b).

- Retain existing vegetation by using retaining walls on fill slopes, reducing surface disturbance, and protecting roots from damage during excavations (BLM, 2005b).

- Enhance revegetation by mulching cleared areas; controlling planting times; furrowing slopes; planting holes on cut/fill slopes; choosing native plant species; stockpiling and reusing topsoil; and fertilizing, mulching, and watering vegetation (BLM, 2005b).

- Minimize the impact on existing vegetation by partial cutting instead of clear cutting, using irregular clearing shapes, feathering/thinning edges, disposing of all slash, controlling construction access, utilizing existing roads, limiting work within the construction area, selecting the appropriate type of equipment to be used, minimizing the clearing size (i.e., strip only when necessary), and grass seeding of cleared areas (BLM, 2005b).

- Maintain the integrity of vegetative units by utilizing the edge effect for structure placement along natural vegetative breaks (BLM, 2005b).

- Minimize the impact of utility crossings by making crossings at right angles, setting back structures at a maximum distance from the crossing, leaving vegetation along the roadside, minimizing viewing time, and utilizing natural screening (BLM, 2005b).

- Recognize the value and limitations of color by painting structures somewhat darker than the adjacent landscape to compensate for the effect of shade and shadow and selecting color to blend with the land and not the sky. Realize that color (hue) is most effective within 1,000 feet. Beyond that point color becomes more difficult to distinguish and tone or value determines visibility and resulting visual contrast. Also, color has limited effectiveness (in the background distance zone) in reducing visual impacts on structures that are silhouetted against the sky (BLM, 2005b).

- Bury pipelines, utility lines, or other cables, whenever possible.

- Avoid creating potential sources of dust by covering construction truck beds, avoiding stockpiling of materials that may blow dust, covering materials, and using other dust suppression methods.

4.7.4.3 Operation

- Maintain good housekeeping procedures. Do not allow trash, debris, unused or broken equipment and materials, or hazardous wastes to unnecessarily accumulate. Keep the amounts of materials stored on-site to a minimum. Maintain the painting and upkeep of the structures.

4.7.5 Regional Considerations

Potential impacts on aesthetic and scenic resources from carbon sequestration projects would be comparable among the various states. As described in Sections 2.3 and 2.4, the availability of CO_2 sources and potential sequestration sinks largely determines the applicability of various technologies in particular states and regions. Section 4.8.4 in land use provides additional discussion of potential locations of various coal seams, depleted oil and gas reserves, saline formations, and other geologic formations for sequestration, as well as cropland, agricultural lands, and forests that could be used for terrestrial sequestration. The potential for visual impacts in each particular region depends on the location of a national park, scenic byway, or other scenic resource in proximity to potential sequestration locations. Significant impacts on scenic resources can be avoided by effective site selection and design.

4.7.6 Summary of Potential Impacts

Table 4-21 provides an overall qualitative assessment of potential impacts to aesthetic and scenic resources for each sequestration technology. For the most part, potential impacts would be negligible to minor during construction stage. Potential long-term impacts from operations would be negligible to moderate, depending upon the location of surface facilities. The need for cleared and maintained pipeline corridors for CO_2 transmission may result in the moderate impacts (long-term and localized) on scenic resources. However, significant adverse impacts can be avoided by using existing corridors where feasible and by carefully routing pipeline corridors not to interfere with scenic vistas and resource areas. Selecting appropriate truck routes that avoid sensitive resources could minimize the impact on scenic resources from additional truck traffic between the capture facility and the sequestration site.

The impacts to aesthetic and scenic resources posed by coal seam, EOR, saline, and basalt sequestration as well as co-sequestration of H_2S and CO_2 would yield similar minor adverse impacts (short-term and localized) because they are all associated with site-clearing activities or site-placement. Post-combustion capture would yield negligible impacts (little or no change) because these projects would likely be located in industrialized areas. CO_2 compression and transport would yield moderate adverse (long-term and localized) impacts because these projects may require new rights-of-way that would have to be cleared of vegetation for site access. Terrestrial reforestation projects would yield net beneficial impacts (long-term restoration) because they will include re-vegetating landscapes that have been substantially degraded by fossil-fuel extraction.

Table 4-21. Potential Impacts of Program Technologies on Aesthetic and Scenic Resources

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Scenic Resources	·	⦿	○	○	○	○	+	○

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

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4.8 LAND USE

This section describes the potential impacts to land use that could occur during the implementation of carbon sequestration technologies. The land resources that could be affected by sequestration technologies are described in Section 3.8. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.8.1 Impact Considerations

Potential impacts on land use have been assessed using the general criteria outlined below and the impact definitions found in Section 4.1.1. Short-term impacts for land use are defined as impacts occurring during the construction timeframe. Localized impacts for land use are defined as those occurring within the project footprint.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Introduce structures and uses that are incompatible with land uses on adjacent and nearby properties (including noise and visual impacts).
- Introduce structures or operations that require substantial restrictions on current land uses on or adjacent to a proposed site.
- Conflict with a jurisdictional zoning ordinance.
- Conflict with a jurisdictional noise ordinance or other ordinance restricting land use.
- Conflict with a local or regional land use plan or policy.

4.8.2 Regulatory Framework

In general, land use in the U.S. is regulated on a local and regional basis. Impacts on land use from the implementation of carbon sequestration technologies would be related to the compatibility of proposed facilities with existing land uses, zoning, and land use plans in locations where they would be sited, as well as construction-related impacts on surrounding communities and land uses. Impacts may also result from potential restrictions on land uses that would be required for the implementation of proposed projects, such as restrictions on land uses to achieve terrestrial sequestration project goals, the need to provide buffer zones for geologic sequestration projects, or the need for CO_2 transmission corridor easements. Carbon sequestration projects would need to consider applicable federal, state, and local laws and regulations concerned with land use. The Farmland Protection Policy Act of 1981 (7 USC§ 4201) is intended to minimize the impact Federal programs have on the unnecessary and irreversible conversion of farmland to nonagricultural uses. It assures that—to the extent possible—Federal programs are administered to be compatible with state, local units of government, and private programs and policies to protect farmland.

4.8.3 Generalized Siting and Operational Impacts of Technologies

4.8.3.1 Post-Combustion Capture

Post-combustion capture projects would be retrofitted to existing, or added to proposed, fossil fuel combustion facilities. Generally, adding a CO_2 capture process to an existing or proposed industrial site would not alter the character or use of the property. Thus, it would not conflict with existing land uses or zoning ordinances and would have a negligible impact on surrounding communities. An exception would occur if the new process required a significant expansion of the facility property or would otherwise introduce features (increased air emissions, noise, hazardous materials, etc.) that would adversely affect adjacent land uses and nearby communities.

Post-combustion capture projects would generally fall within the site boundary of the power plant or other source facility. However, if a CO_2 capture project created a need to acquire additional land for the facility, an assessment of site-specific impacts on land use would be required based on criteria provided in Section 4.8.1. In the event that a post-combustion capture process would be associated with a proposed new industrial facility, the environmental review for the new facility would address all site-specific impacts on land use.

Most processes available for post-combustion CO_2 capture, such as the use of sorbents or separation membranes, would not introduce features that would adversely affect adjacent land uses when compared to the features of an existing or proposed combustion power plant. Therefore, the contributions of a CO_2 capture process to air emissions, hazardous materials, noise, and other features already associated with a power plant or comparable industrial process would have negligible additional impacts on adjacent land uses and nearby communities. However, the requirements for delivery of sorbents or other materials and the removal of wastes may increase the numbers of trucks entering and leaving the property on a daily basis, which would be addressed from the perspective of traffic impacts in site-specific NEPA documents.

4.8.3.2 CO_2 Compression and Transport

As described in Section 2.5, CO_2 compression facilities would require a small footprint of land located in proximity to a CO_2 capture process, most likely on the property of an existing power plant or comparable industrial facility. Generally, the addition of CO_2 compression facilities to an existing or proposed industrial site would not conflict with existing land uses or zoning ordinances and would have a negligible impact on surrounding communities. An exception would occur if the new process required new site acquisition or significant expansion of the facility property, or if it would otherwise introduce features (increased air emissions, noise, hazardous materials, etc.) that would adversely affect adjacent land uses and nearby communities.

Transport of CO_2 could be from compression facilities to sequestration sites via compressed gas pipeline or via commercial refrigerated tank trucks as described in Section 2.5. It has been assumed that a cost-effective commercial-scale project would likely provide conveyance by pipeline over a distance of approximately 20 miles or less. Therefore, the principal aspect of a CO_2 compression and transport project that would affect land use is the potential need for easements and rights-of-way for underground CO_2 pipelines and access roads. Where practicable, impacts on land use can be minimized by utilizing easements already established for other utility pipelines and power transmission lines. Otherwise, new easements would be required, which would necessitate an assessment of site-specific impacts on land use based on criteria in Section 4.8.1. In the event that tank trucks would transport CO_2, the principal impacts on surrounding land uses would be related to the numbers of trucks entering and leaving the respective compression and sequestration sites on a daily basis.

Because CO_2 is an inert, non-toxic gas, the establishment of easements for pipeline corridors would not necessarily impose significant restrictions on many land uses affected by the easements. However, the easements would generally require that the corridors remain cleared of large trees and be accessible for inspection and maintenance of the pipelines, that permanent structures may not be built within the easements, and that subsurface excavation may not occur. The easements would remain suitable for open-space

> Establishment of easements for pipeline corridors would not necessarily impose significant land use restrictions on the easement. Easements would remain suitable for open-space recreation and would not necessarily interfere with grazing and other agricultural uses.

recreation and would not necessarily interfere with grazing and other agricultural uses.

4.8.3.3 Sequestration in Coal Seams

Siting for coal seam sequestration projects would depend on the identification of suitable coal seams within sufficient proximity of potential CO_2 sources to enable cost-effective conveyance. Hence, unmineable coal seams closest to existing fossil fuel-fired power plants or other CO_2 sources would be the optimal candidates for the application of a pilot or commercial scale project initially. Also, because site selection would be subject to local land use regulations and controls, as well as state and federal regulations affecting injection wells, current variations in the restrictions of local zoning ordinances and land use policies, as well as variations in state regulations, would likely influence the feasibility of siting a project in a particular location. Furthermore, the suitability of a prospective sequestration project would be affected by the proximity of coal seams to populated areas. Finally, a host of economic considerations would affect site selection, including the feasibility of future coal extraction from the seam by the holder of the mineral rights, the nature of the terrain, the accessibility of a proposed site, and the availability of suitable rights-of-way for conveyance corridors. Hence, before selecting a suitable location for a coal seam sequestration project, an assessment of site-specific impacts on land use would be required using the criteria provided in Section 4.8.1.

The most promising initial candidate sites for coal seam sequestration would include unmineable coal seams in areas that have already been disturbed by activities during previous coal mining operations.

Assuming that candidate coal seams underlie properties in all of the major land uses described in Section 3.8, it is feasible that potential sites for projects may be located in any category of land use. However, the siting of coal seam sequestration projects generally would avoid urban jurisdictions. Therefore, sites chosen for coal seam injection and associated MM&V facilities most likely would not be subject to local zoning ordinances, or they would likely be zoned for mineral extraction, agriculture, or other rural uses. Similarly, if feasible sites for coal seam sequestration were subject to comprehensive land use planning, they most likely would be designated for open space, recreation, agriculture, or comparable uses.

Based on the relatively small site footprints required for surface facilities associated with a coal seam sequestration project, the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities essentially would affect underground resources, aboveground uses in the majority of lands needed for coal seam sequestration projects generally would not be altered. Hence, forested areas, croplands, grasslands, and virtually all other lands overlying the affected coal seam could remain in their existing uses.

4.8.3.3.1 Split Estate Lands

While it is expected that new enhanced coalbed methane projects (that sequester CO_2) will occur primarily at existing coalbed methane extraction operations, it is possible that the ability to enhance its extraction would result in the expansion of existing projects or the placement of new coalbed methane operations on previously undisturbed lands. A significant amount of coalbed methane is located in the western U.S. (Figure 3-20) where in many places the mineral rights are owned not by the overlying land owner, but by the federal government.

Over the course of U.S. history, a series of Homestead Acts passed by Congress provided for the transfer of unoccupied land to each homesteader for a nominal fee. A patent certificate could be obtained from the homesteader after continuously residing on and cultivating the land for five years (WYSEI, 2005). Many patent agreements in the West included a subsurface reservation clause that includes the retention of the mineral rights to the federal government. This separation in ownership creates a situation where the minerals are owned by one entity and the surface is owned by a second entity, referred to as a "split estate" (WYSEI, 2005). Montana and Wyoming have over 11 million acres of split-estate lands (federal mineral rights under private surface lands) apiece. New Mexico, Colorado, North Dakota, Idaho, Arizona, Oregon, South Dakota and Utah individually have over a million acres of split-estate land.

Increasingly, landowners of split-estate lands are resisting the extraction of oil and gas from their lands. During the second half of the 1990's, CBM production increased dramatically nationwide to represent a significant new source of natural gas. In recent years, exploration and development of CBM has been under intense scrutiny, as heightened concerns over environmental issues relating to production practices increased (DOE, 2002).

In the 2003 BLM Powder River Basin Coalbed Methane Final EIS, BLM predicted that an estimated 40,000 additional CBM wells would be drilled over the next 10 years on federally-owned minerals, which could disturb as many as 212,000 acres. In response to the expansion of drilling proposed by BLM, Wyoming grassroots organizations, consisting of individuals and affiliate groups, applied for Environmental Conflict Resolution to investigate split estate issues involved with CBM development of the Powder River Basin.

Because the mineral rights owner (Federal government) has a dominant legal right to access and develop the minerals, those who own the surface rights often feel that their property rights have been violated during the CBM development process (U.S. Institute for Environmental Conflict Resolution, 2003). Some key concerns raised by landowners in the case of the Powder River Basin include:

- Perceived threat to the ranching way of life – that drilling wells with roads and power lines may lead to eventual subdivision of the land.
- Concern regarding the method of discharge of produced water.
- Oversight and enforcement of the Surface Use and Damage Agreement (SUDA) is extremely time consuming, where time is not compensated and results in lost work hours.
- Financial hardships associated with the legal costs of fighting CBM development or negotiating a protective SUDA.
- Perception that CBM development is greatly lowering the value of their properties by degrading the scenic beauty and open landscape.
- Feeling that current state and federal government bonding requirements are grossly inadequate.

Although this reflects some of the landowner views on resource extraction in one basin, similar land use and property concerns could be attributed to the federal sale of mineral rights underneath other areas of private land in other regions of the U.S.

In April 2003, BLM instituted an Instruction Memorandum that clarified the policy, procedures and conditions for approving oil and gas operations on split estate lands. Under this memorandum, BLM will not consider an Application for Permit to Drill administratively or technically complete until the federal lessee or its operator certifies that an agreement with the surface owner exists, or until the lessee or its operator complies with Onshore Oil and Gas Order No. 1. This order requires the Federal mineral lessee or its operator to enter into good-faith negotiations with the private surface owner to reach an agreement for the protection of surface resources and reclamation of the disturbed areas, or payment in lieu thereof, to compensate the surface owner for loss of crops and damages to tangible improvements. Crops include those for feeding domestic animals, such as grasses, hay, and corn, but not plants unrelated to stockraising.

Tangible improvements include those relating to domestic, agricultural and stockraising uses (BLM, 2004).

Although this BLM policy will aid in diminishing concerns of owners of split estate lands, it is expected that conflicts over the use of split estate lands will continue. Subsequently, both the government and industry need to be sensitive to landowner concerns and use a collaborative process to develop SUDAs that reduce environmental impacts and minimize disruption to current land uses.

4.8.3.4 Sequestration in Depleted Oil and Gas Reserves

The most promising candidate locations initially for pilot scale and commercial scale sequestration would include depleted oil and gas reserves that are situated within close proximity of fossil fuel-fired power plants or other large CO_2 sources. It is also likely that candidate sites would be situated on lands that have been substantially disturbed during years of oil and gas production.

Most of the assumptions pertaining to land uses associated with coal seam sequestration would be similar for depleted oil and gas reserves. Candidate sites may underlie properties in any of the major land uses described in Section 3.8; however, the siting of sequestration projects generally would avoid urban jurisdictions. Therefore, sites chosen for sequestration and associated MM&V facilities probably would not be subject to local zoning ordinances, or they would be zoned for uses compatible with oil and gas extraction. If addressed by comprehensive land use plans, suitable sites most likely would be designated for open space, recreation, agriculture, or comparable uses.

Based on the relatively small site footprints required for surface facilities associated with a sequestration project in a depleted oil or gas reserve, the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities would essentially affect underground resources, aboveground uses for the majority of lands needed for sequestration projects would not generally be affected. Hence, grasslands, croplands, forested areas, and virtually all other lands could remain in their current uses.

4.8.3.5 Sequestration in Saline Formations

The siting of projects to sequester CO_2 in saline formations would depend on the identification of suitable formations sufficiently near potential CO_2 sources to enable cost-effective conveyance. Site clearing for the development of surface structures, wells, equipment locations, and access roads would necessitate the disturbance of land.

Although the surface facilities needed for sequestration in saline formations would be similar to those for sequestration in unmineable coal seams and depleted oil and gas reserves, saline formations would not necessarily be associated with lands that have been disturbed during prior resource extraction. Hence, before selecting a suitable location for a saline sequestration project, an assessment of site-specific impacts on land use would be required using the criteria provided in Section 4.8.1. On a nationwide and regional basis, variations in local zoning, as well as in state programs pertaining to injection wells, would likely influence site selection.

Most of the assumptions pertaining to land uses associated with coal seam sequestration would be similar for saline formations. Candidate sites may underlie properties in any of the major land uses described in Section 3.8; however, the siting of sequestration projects generally would avoid urban jurisdictions. Therefore, sites chosen for sequestration and associated MM&V facilities would probably not be subject to local zoning ordinances, or would be zoned for agriculture and other rural uses. If addressed by comprehensive land use plans, suitable sites most likely would be designated for open space, recreation, agriculture, or comparable uses.

Based on the relatively small site footprints required for surface facilities associated with a sequestration project in a saline formation, the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities would essentially affect underground resources, aboveground uses for the majority of lands needed for sequestration projects would not generally be affected. Hence, grasslands, croplands, forested areas, and virtually all other lands could remain in their current uses.

4.8.3.6 Sequestration in Basalt Formations

The siting of projects to sequester CO_2 in basalt formations would depend on the identification of suitable formations sufficiently near potential CO_2 sources to enable cost-effective conveyance. Site clearing for the development of surface structures, wells, equipment locations, and access roads would necessitate the land disturbance.

Although the surface facilities needed for sequestration in basalt formations would be similar to those for sequestration in unmineable coal seams and depleted oil and gas reserves, basalt formations would not necessarily be associated with lands that have been disturbed during prior resource extraction. Hence, before selecting a suitable location for a basalt sequestration project, an assessment of site-specific impacts on land use would be required using the criteria in Section 4.8.1. On a nationwide and regional basis, variations in local zoning, as well as in state programs pertaining to injection wells, would likely influence site selection.

Most of the assumptions pertaining to land uses associated with coal seam sequestration would be similar for basalt formations. Candidate sites may underlie properties in any of the major land uses described in Section 4.8; however, the siting of sequestration projects generally would avoid urban jurisdictions. Therefore, sites chosen for sequestration and associated MM&V facilities would probably not be subject to local zoning ordinances, or would be zoned for agriculture and other rural uses. If addressed by comprehensive land use plans, suitable sites most likely would be designated for open space, recreation, agriculture, or comparable uses.

Based on the relatively small site footprints required for surface facilities associated with a sequestration project in a basalt formation, the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities would essentially affect underground resources, aboveground uses for the majority of lands needed for sequestration projects would not generally be affected. Hence, grasslands, croplands, forested areas, and virtually all other lands could remain in their current uses.

4.8.3.7 Terrestrial Sequestration - Reforestation

As described in Section 2.5, many terrestrial sequestration projects would involve efforts to reclaim and restore degraded landscapes through reforestation and afforestation that would convert CO_2 into biomass. Such projects would not normally cause adverse changes in land use, because it is assumed that candidate sites are already located on lands that have been degraded by prior mining operations for fossil fuel or mineral extraction and that such sites are most likely planned and zoned for reclamation as open space or recreational lands. Instead, the reclamation of degraded lands would have a net beneficial impact on open space utilization. However, if a potential project would alter land use in a manner that would adversely affect surrounding communities and land uses, an assessment of site-specific impacts on land use would be required.

4.8.3.8 Co-Sequestration of H_2S and CO_2

Co-sequestration of H_2S and CO_2 would be similar to sequestration of CO_2 in coal seams, oil and gas reserves, and saline formations. The facilities and infrastructure would be similar, however, different materials for pumps, compressors, and pipelines would be used to guard against the corrosive nature of the sour gas. As with the aforementioned model projects, based on the relatively small site footprints required for surface facilities the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities would essentially affect underground resources, aboveground uses for the majority of lands needed for sequestration projects would not generally be affected. Hence, grasslands, croplands, forested areas, and virtually all other lands could remain in their current uses.

4.8.4 Mitigation of Potential Adverse Impacts

The following measures are recommended to mitigate potential adverse impacts of sequestration technologies on land use:

4.8.4.1 Project Planning and Design

- Plan for efficient use of land and consolidation of infrastructure requirements as practical. Site design elements should be integrated with surrounding land uses. Establish appropriate buffer areas to minimize impacts on surrounding land uses.

- If the project (e.g., pre-combustion decarbonization, post-combustion capture) will be located at an existing industrial facility, determine whether adequate, suitable land area is available to accommodate new facilities without affecting established buffer areas or encroaching on adjacent land uses.

- If the project will require the acquisition of new sites for facilities, avoid areas that may result in land use conflicts. Consult local zoning maps and ordinances during the site selection process to determine whether the project would comply with restrictions on land use in respective zones.

- Confer with local and regional planning agencies and zoning authorities early during the site selection process to identify regional land use plans and policies that may create challenges for the proposed project, local ordinances that may restrict particular uses, and other sensitive land uses and potential planning goals and issues specific to the region that should be considered during project planning.

- If a project were to be located on lands controlled by federal or state agencies, confer with the appropriate representatives of the respective landowner to determine potential limitations and restrictions that may be applicable to the project.

- If a project were to be located on tribal lands, follow established DOE policies for consultation with the appropriate tribal representatives to determine potential limitations and restrictions that may be applicable to the project.

- Where appropriate, based on the identification of proposed project sites and on local, regional, Federal, or tribal land use plans and policies, undertake amendment of applicable land use plans in coordination with respective planning authorities to ensure compatibility with the proposed project.

- Determine whether rights-of-way will be required for pipeline corridors, access roads, or other facilities. Identify established easements that may be available to accommodate additional pipelines or access roads in the proposed transmission corridor and minimize the need for new easements. If new rights-of-way will be required, ensure that all of the preceding recommendations are followed during planning for corridor alignments.

4.8.4.2 Construction

- Adhere to site plans and minimize the footprint of land area disturbance required for a proposed project, including permanent structures, roads, temporary structures, staging areas, and other features.

- Maintain buffer zones to minimize construction impacts on adjacent communities and land uses.

- Limit trucking operations for deliveries and removals to non-peak periods, while avoiding noise-sensitive times of day, to minimize traffic and noise impacts on adjacent communities and land uses.

- Restrict construction activity to the least noise-sensitive times of day in accordance with local ordinances to minimize noise impacts on adjacent communities and land uses.

- Locate stationary construction equipment as far as practicable from property boundaries and adjacent communities.

- Require the implementation of noise suppression equipment and BMPs to reduce noise to acceptable levels at property boundaries of adjacent communities. For example, require sound-muffling devices on construction equipment that are no less effective than as provided on original equipment and ensure that devices are properly maintained.

- Implement BMPs for control of construction-related air emissions, erosion and sedimentation control, and habitat protection as described for other respective resources to minimize adverse impacts on adjacent land uses and communities.

- Reclaim and restore disturbed areas expeditiously in accordance with established landscaping plans for the project site upon completion of construction phases.

4.8.4.3 Operation

- Conduct facility operations within established local ordinances, as well as Federal and state regulations, to minimize impacts on surrounding communities and land uses.

- Limit trucking operations for deliveries and removals to non-peak periods to minimize traffic impacts on adjacent communities and land uses.

- Limit noise-emitting operations to the least noise-sensitive times of day in accordance with local ordinances to minimize noise impacts on adjacent communities and land uses.

- Require the implementation of noise suppression equipment and BMPs to reduce noise to acceptable levels at property boundaries of adjacent communities. For example, require sound-muffling devices on operational equipment that are no less effective than as provided on original equipment and ensure that devices are properly maintained.

4.8.5 Regional Considerations

The potential for impacts on land use from respective capture and sequestration projects would be comparable among the various states. The technologies and features associated with potential projects, as well as particular restrictions in jurisdictional ordinances, regional land use policies, and state regulations would more likely affect land use impacts. As described in Sections 2.3 and 2.4, the availability of CO_2 sources and potential sequestration sinks largely determines the applicability of various technologies in particular states and regions. The principal land uses that may be found in the prospective project locations are described in the following paragraphs.

In the Midwest states, candidate locations for sequestration in coal seams and depleted oil and gas reserves generally overlap in a band that coincides with the Appalachian Mountain range stretching from eastern Kentucky north to western Pennsylvania. These lands are predominantly forested. Additional geologic sequestration opportunities include coal seams and depleted oil and gas reserves in areas of central Michigan that are mainly cropland and forest. Saline formations also underlie cropland and forest in portions of Ohio and Michigan. Also, in addition to the extensive forested areas of West Virginia, Pennsylvania, Ohio, and Kentucky that already provide natural sequestration, opportunities for reclamation of mined lands in these states provide potential project sites for terrestrial sequestration through reforestation and afforestation.

Potential opportunities for geologic sequestration are found throughout most of Illinois, as well as southwestern Indiana and western Kentucky. In these areas, layers of coal seams, depleted oil and gas reserves, and saline formations underlie lands that are characterized by cropland and pasture.

The best candidate areas for geologic sequestration in the southeast include depleted oil and gas reserves and saline formations underlying areas in eastern Texas, Louisiana, Mississippi, and Alabama that are characterized by grassland and forest. Coal seams underlie forested lands in parts of northern Alabama, eastern Tennessee, and southwestern Virginia. In addition to the extensive forested areas in the region that already provide natural sequestration, opportunities for reclamation of degraded lands in these states provide potential project sites for terrestrial sequestration through reforestation and afforestation.

Depleted oil and gas fields are located extensively in Texas, Oklahoma, Kansas, Colorado, and New Mexico, and to a lesser extent in other states in the southwest. Saline formations are located in many of the same areas. Most of these resources underlie pasture and cropland in these states. Coal seams also underlie pasture and cropland in eastern Nebraska, Kansas, Oklahoma, and parts of Texas. Other coal seams underlie grassland and forest in parts of Wyoming, Utah, Colorado, and New Mexico. Degraded landscapes from prior mineral extraction throughout the region provide abundant opportunities for terrestrial sequestration projects.

In the west, the most promising sites for geologic sequestration in California are saline formations, and oil and gas reservoirs which are found throughout the Central Valley. In Arizona, suitable saline formations may be found in the northeast. Saline formations are also present in the coastal valleys of Oregon and Washington. Alaska has vast oil and gas reservoirs, saline formations and coal deposits that may be suitable for carbon sequestration projects.

Coal seams, depleted oil and gas reserves, and saline formations underlie grassland and cropland in parts of Montana. Lands degraded during prior mineral extraction in the region offer prospects for terrestrial sequestration projects.

Opportunities for geologic sequestration in the plains include coal seams that underlie cropland and pasture in Iowa and Missouri, as well as oil and gas reserves that underlie grassland and cropland in North Dakota, Wyoming, and Montana. Disturbed landscapes from prior mining operations throughout the region provide abundant opportunities for terrestrial sequestration projects.

4.8.6 Summary of Potential Impacts

Because sequestration projects essentially affect underground resources, aboveground uses for the majority of lands required for projects would not generally be affected.

Table 4-22 provides an overall qualitative assessment of potential impacts to land use for each sequestration technology. Based on the relatively small site footprints required for surface facilities, the impacts on land uses in rural areas would be negligible to minor in most cases. Because the project activities would essentially affect underground resources, aboveground uses for the majority of lands needed for sequestration projects would not generally be affected. Reforestation would be expected to have a beneficial impact on land use by reclaiming previously mined lands.

The impacts to existing land uses posed by coal seam, EOR, saline, and basalt sequestration as well as co-sequestration of H_2S and CO_2 would yield similar minor adverse impacts (short-term and within existing zoning laws) because they will each require relatively small site footprints located in rural areas. CO_2 compression and transport would also yield minor adverse impacts if the new process required new site acquisition or significant expansion of existing facilities, however in general terms, the impacts of this technology would be negligible (little or no change) because they would be added onto existing industrial facilities. Post-combustion capture would yield negligible impacts because these projects would involve retrofitting existing or adding onto proposed industrial facilities. Terrestrial reforestation projects would yield net beneficial impacts (long-term restoration) because they will include re-vegetating landscapes that have been substantially degraded by fossil-fuel or mineral extraction.

Each of the aforementioned technologies, except for terrestrial reforestation, would impose similar, negligible impacts (little or no change) on zoning and land use planning because they would be situated in either rural areas that would be zoned for rural uses or not be subject to local zoning ordinances at all or in existing industrialized areas. Terrestrial reforestation would have a net beneficial impact (long-term restoration) on land use planning because it is assumed that candidate sites would most likely be planned and zoned for reclamation as open space or recreational lands.

Table 4-22. Potential Impacts of Program Technologies on Land Use

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Existing land use	·	○	○	○	○	○	+	○
Zoning and other ordinances	·	·	·	·	·	·	·	·
Land use planning	·	·	·	·	·	·	+	·

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.9 MATERIALS AND WASTE MANAGEMENT

This section describes the potential environmental impacts from use of hazardous materials and disposal of waste from the implementation of carbon sequestration technologies. Baseline information regarding materials and waste management as they relate to carbon sequestration technologies are described in Section 3.9. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.9.1 Impact Considerations

Potential impacts have been assessed using the general criteria outlined below and the impact definitions in Section 4.1.1. Short-term impacts for materials and waste management are defined as impacts occurring during the construction timeframe. Localized impacts from materials and waste management are defined as occurring within the county(s) in which the project resides (as most waste is usually directed towards local and county landfills).

The following definitions are used in this section:

- **Solid Waste** means garbage, and other discarded solid materials resulting from industrial, commercial and agricultural operations, and from community activities.
- **Municipal Solid Waste** means solid waste resulting from or incidental to residential, community, trade or business activities, including garbage, rubbish, ashes, and all other solid waste.
- **Hazardous Waste** means any waste or combination of wastes which pose a substantial present or potential hazard to human health, the environment, and plants or animals because such wastes are nondegradable or persistent in nature, can be biologically magnified, can be lethal, or may otherwise cause or tend to cause detrimental cumulative effects.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Creates volumes of wastes (directly or indirectly) that exceed the capacity of solid waste collection services and landfills.
- Creates wastes for which there are no commercially available disposal or treatment technologies.
- Creates unsafe conditions for employees or surrounding neighborhoods.
- Creates hazardous wastes in quantities that would require a Treatment, Storage, and Disposal (TSD) permit.
- Creates reasonably foreseeable conditions that would significantly increase the risk of a release of hazardous waste or hazardous material.

In general, the implementation of carbon sequestration technologies would be related to the materials used in the construction and operation phases of proposed facilities and the wastes that would be generated. Impacts would be different and would depend on the technologies that would be used for sequestration projects, size of the facilities and the location.

The initial step in determining the potential impacts of the use of materials and the waste management practices is to determine the materials and wastes that would be used at the proposed facility. At this early stage in the planning of projects, the precise list of materials used and wastes that would be generated is not complete. However, the types of materials and wastes for some of the projects can be assumed. The following sections list the materials and waste streams that would be expected for the type of facility being analyzed. This is based on similar facilities that are already in operation or processes that are similar.

The early stage of planning also provides little or no information about the locations where the technology projects would be sited. Therefore there is no information to form the basis for the potential of hazardous waste to pose a risk to surrounding communities.

A broad assumption is included that each proposed facility would operate within the limits of environmental permits that would be obtained and applicable DOE directives, such as those listed in Table 4-23, as well as other applicable state, federal, and local regulations. Another assumption is that a Material Safety Data Sheet (MSDS) would be obtained from the manufacturer for each hazardous material used in the project construction or operation. It is expected that sequestration projects would not create wastes for which no ultimate treatment or disposal is available. Each of the technology projects would include a sanitary sewage system during the operational phase of the project. The construction phase of the projects may be served by portable toilets.

4.9.2 Regulatory Framework

4.9.2.1 Federal Laws and Policies

Several federal laws and related policies have been enacted to govern the management of materials and waste resources. The most significant regulations include:

- ***Resource Conservation and Recovery Act (RCRA).*** This Act gives the EPA the authority to regulate the generation, transportation, treatment, storage, and disposal of hazardous wastes ("cradle-to-grave" management). The most significant of the ten subtitles of RCRA is subtitle C, which establishes the national hazardous waste management program. The 1986 amendments to RCRA provide the EPA with regulatory authority over underground storage tanks (USTs) containing hazardous substances and petroleum. RCRA focuses only on active and future facilities. Of particular note is Section 3004(u) (i.e., corrective action) by which the EPA or a state may require the cleanup or a schedule for investigation and cleanup of all inactive Solid Waste Management Units on an installation before issuing a RCRA part B permit for current HW operations at the installation. Note that cleanup standards may be different under RCRA than under the Comprehensive Environmental Response, Cleanup and Liability Act (CERCLA).

- ***Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA) (42 USC §11001 et seq.)*** This statute requires that inventories of specific chemicals used or stored onsite be reported on a periodic basis. The projects would manufacture, process, or otherwise use a number of substances subject to EPCRA reporting requirements.

- ***National Pollutant Discharge Elimination System (NPDES) (33 USC 1342 et. seq.)*** This federal regulation authorized under the CWA requires sources to obtain permits to discharge effluents (pollutants) and stormwaters to surface waters. Regulations implementing the NPDES program are found in 40 CFR 122. Under this program, permit modifications are required if discharge effluents are altered. The CWA authorizes EPA to delegate permitting, administrative, and enforcement duties to state governments, while EPA retains oversight responsibilities.

- ***Spill Prevention Control and Countermeasure (SPCC) Plan***. An SPCC Plan is required if onsite storage of petroleum products in any single tank greater than 660 gallons capacity and/or aggregate quantities greater than 1,320 gallons (this plan is a prerequisite for coverage under the EPA General Stormwater Permit for Construction Activities).

- ***Federal Energy Regulatory Commission (FERC), Section 7 Pipeline Permit.*** The application for this permit for construction and operation of a CO_2 pipeline will require preparation of FERC Environmental Resource Reports 1 through 13, which together are the equivalent of a comprehensive Environmental Impact Statement ("EIS").

- ***Toxic Substances Control Act (TSCA) of 1976 (15 USC § 2601).*** This Act provides for the Federal regulation of chemical substances that present a hazard to health or the environment. Such regulation requires the testing of new substances and subsequent control of their commercial distribution. The Act also contains specific requirements relative to polychlorinated biphenyls, asbestos, and radon.

- ***DOE O 231.1. Environment, Safety and Health Reporting.*** To ensure timely collection, reporting, analysis, and dissemination of information on environment, safety, and health issues as required by law or regulations or as needed to ensure that the DOE and National Nuclear Security Administration are kept fully informed on a timely basis about events that could adversely affect the health and safety of the public or the workers, the environment, the intended purpose of DOE facilities, or the credibility of the Department.

Several DOE directives relate to materials and waste management aspects of carbon sequestration projects as listed in Table 4-23.

Although the facilities would be owned by the project proponent, compliance with DOE directives may be required as part of the cost sharing agreement with DOE even though the facilities would not be owned by DOE or staffed by DOE or contractor employees.

Table 4-23. DOE Directives Addressing Materials and Waste Management

Directive Number	Title	Purpose
DOE O 231.1A	Environment, Health and Safety Reporting	To ensure timely collection, reporting, analysis, and dissemination of information on environment, safety, and health issues as required by law or regulations or as needed to ensure that the Department of Energy (DOE) is kept fully informed on a timely basis about events that could adversely affect the health and safety of the public or the workers, the environment, the intended purpose of DOE facilities, or the credibility of the Department.
DOE P 411.1	Safety Functions, Responsibilities and Authorities Policy	The DOE has the responsibility to ensure that operations at its facilities are conducted safely. The purpose of this policy and the associated manual is to define the DOE safety management functions, responsibilities and authorities to ensure that work is performed safely and efficiently. This policy statement succinctly defines the Department's expectation regarding DOE employees' responsibilities for safety management.
DOE O 440.1A	Worker Protection Management for DOE Federal and Contractor Employees	To establish the framework for an effective worker protection program that will reduce or prevent injuries, illnesses, and accidental losses by providing DOE Federal and contractor workers with a safe and healthful workplace.

Directive Number	Title	Purpose
DOE O 450.1	Environmental Protection Program	To implement sound stewardship practices that are protective of the air, water, land, and other natural and cultural resources impacted by DOE operations and by which DOE cost effectively meets or exceeds compliance with applicable environmental; public health; and resource protection laws, regulations, and DOE requirements.
DOE O 460.2	Departmental Materials Transportation Packaging and Management	To establish Department of Energy (DOE) policies and requirements to supplement applicable laws, rules, regulations, and other DOE Orders for materials transportation and packaging operations.
DOE 5480.4	Environmental Protection, Health, Safety and Health Protection Standards	To specify and provide requirements for the application of the mandatory environmental protection, safety, and health (ES&H) standards applicable to all DOE and DOE contractor operations, to provide a listing of reference ES&H standards; and to identify the sources of the mandatory and reference ES&H standards.

Source: DOE, 2005.

4.9.3 Generalized Construction and Operational Impacts of Technologies

4.9.3.1 Post-combustion Capture

4.9.3.1.1 Construction

Post-combustion capture projects would be retrofitted to existing, or added to proposed, fossil fuel combustion facilities or comparable industrial processes. Materials used during construction would include items common to industrial construction: concrete, wood, steel, plastics, composites, and paint. Hazardous materials such as solvents used in construction would be managed according to the applicable requirements of the RCRA, state requirements and DOE directives. Solvents that cannot be recycled would be sent to a permitted Treatment Storage and Disposal (TSD) facility for treatment and/or disposal. Industrial-related solid wastes would be generated including scrap wood and steel, and other leftover construction materials. This waste would be disposed in a local landfill that is permitted to accept such waste. It is too early in the planning process to know the specific information about landfill capacities.

4.9.3.1.2 Operations

Materials and wastes that are assumed to be used or generated, aside from solid waste, are listed in Table 4-24. A post-combustion capture project would include equipment and process streams to separate CO_2 from other gases in the exhaust stream from a co-located plant.

Solid wastes would be generated and would be transported by truck to a nearby permitted landfill. Most processes available for post-combustion CO_2 capture, such as the use of sorbents or separation membranes, would not introduce features that have unknown or substantially more hazardous materials when compared to the features of an existing or proposed combustion power plant. Wastes that would be produced such as spent carbon from amine filter beds and disposable filter cartridges can be disposed of safely without unusual risk to workers or members of the public.

Table 4-24. Materials and Waste Streams

Project	Material/Waste Stream	Management or Materials or Wastes[1]
Post-combustion Capture	Amine Reclaimer Sludge	Approximately 530 tons per month would be transported by truck to a permitted municipal landfill.
	Spent Carbon from amine filter beds	Approximately 16 tons per month would be transported by truck to a permitted municipal landfill
	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.
CO_2 Compression and Transport	Anhydrous ammonia	Ammonia is used in commercial compressors and is stored in a large tank.
	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.
Sequestration in Coal Seams	Drilling Cuttings and Drilling Mud	Cuttings and drilling mud would be disposed in place or at a local permitted landfill depending on the state and local requirements.
	Tracers	A variety of tracers may be injected into wells with the CO_2 to measure the movement of CO_2 in geologic formations. See Table 4-76 for a list of tracers that may be used.
	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.
Sequestration in Depleted Oil and Gas Reserves	Drilling Cuttings and Drilling Mud	Cuttings and drilling mud would be disposed in place or at a local permitted landfill depending on the state and local requirements.
	Tracers	A variety of tracers may be injected into wells with the CO_2 to measure the movement of CO_2 into geologic formations. See Table 4-76 for a list of tracers that may be used.
	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.
Sequestration in Saline Formations	Drilling Cuttings and Drilling Mud	Cuttings and drilling mud would be disposed in place or at a local permitted landfill depending on the state and local requirements.
	Tracers	A variety of tracers may be injected into wells with the CO_2 to measure the movement of CO_2 into geologic formations. See Table 4-76 for a list of tracers that may be used.
	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.
Terrestrial	Fuel for equipment and standby power generation	Diesel fuel, gasoline, propane, or natural gas may be used. Fuels would be stored in the tanks or other containers that would meet requirements for the particular fuel.

[1] CO_2 will be processed in all of the proposed projects. Proper management and safeguards would be observed to ensure that CO_2 is confined to vessels and pipelines and that any leaks are quickly detected and sealed.

4.9.3.2 CO_2 Compression and Transport

4.9.3.2.1 Construction

Construction activities associated with CO_2 compression and transport projects include retrofitting existing, or addition to proposed, fossil fuel combustion facilities or comparable industrial processes. Materials used during construction would include items common to industrial construction: concrete, wood, steel, plastics, composites, and paint. Hazardous materials such as solvents used in construction would be managed according to the applicable requirements of the RCRA, state requirements and DOE directives. Solvents that cannot be recycled would be sent to a permitted TSD facility for treatment and/or disposal. Industrial wastes would be generated including scrap wood and steel, and other leftover construction materials. Industrial waste would be disposed in a local landfill that is permitted to accept such waste. It is too early in the planning process to know the specific information about landfill capacities.

4.9.3.2.2 Operations

CO_2 compression facilities would require large compressors and pipelines. The CO_2 can be transported from compression facilities to sequestration sites via compressed gas pipeline or via commercial refrigerated tank trucks. It has been assumed that a cost-effective commercial-scale project would likely provide conveyance by pipeline.

Solid wastes would be generated and would be transported by truck to a nearby permitted landfill. Amine filter sludge and carbon from the reclaimer bed would be generated as noted in Table 4-24. Hundreds of gallons per day of water would be generated by the gas compression process. The water would be relatively free of contaminants and could be evaporated onsite or discharged to the onsite sanitary sewer depending on the capacity of the sewer system. The amount of lubricating oil used would depend on the size of the plant. Used lubricating oil would be collected and transported off-site for recycling or other use.

4.9.3.3 Sequestration in Coal Seams

4.9.3.3.1 Construction

Coal seam sequestration projects would be conducted at suitable coal seams near a potential CO_2 source such as a power plant. Materials used during construction would include items common to industrial construction: concrete, wood, steel, plastics and composites. Hazardous materials such as solvents used in construction would be managed according to the applicable requirements of RCRA, state requirements and DOE directives. Solvents that cannot be recycled would be sent to a permitted TSD facility for treatment and/or disposal. Industrial-related solid wastes would be generated including scrap wood and steel, and other leftover construction materials. The wastes would be disposed in a local landfill that is permitted to accept such waste.

The largest volume of waste generated during construction would be from drilling activities in the form of drilling mud and cuttings from the drilling. These drilling wastes would be exempt from RCRA and are considered non-hazardous. Drilling mud containing less than 15,000 mg/l TDS can be disposed of on-site with the landowner's permission. The amount of waste generated is not expected to overwhelm the landfills in the area of a project; however, location specific surveys of local landfill capacities would be needed to determine the level of impact.

4.9.3.3.2 Operations

Solid wastes would be generated and would be transported by truck to a nearby permitted landfill. Other impacts would result from spills of waste during maintenance activities, including waste oil from generators, paint waste from construction activities and other solid wastes from construction activities. Impacts would also occur from the use of pesticides and herbicides during access and construction activities. The construction phase would consist of drilling wells into coal seams for injection of CO_2. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as CH_4. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed and the drilling rig and associated equipment have been demobilized and replaced with a service rig. During the test, increasing pressures of CO_2 injection or borehole fluid would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig and a potentially unsafe condition for workers.

Tracers are sometimes injected into the CO_2 stream so that measurements can be made about the transport of the CO_2 within the formation. Amounts of the tracers that are collected in monitoring wells are compared for their distribution in area and time. The compounds used as tracers are typically nontoxic and will degrade within the formation over time.

> Tracers injected into the CO_2 stream for measurement purposes are typically non-toxic and will degrade within the formation over time.

4.9.3.4 Sequestration in Depleted Oil and Gas Reserves

4.9.3.4.1 Construction

Sequestration in depleted oil and gas reserves is similar to the sequestration in coal seam concept. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation.

The construction phase would consist of drilling wells into depleted oil deposits or reworking existing wells if they are deemed suitable to support the injection of CO_2. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry.

Similar to other sequestration projects that would use well drilling, the largest volume of waste generated during construction would be in the form of drilling mud and cuttings from the drilling. These drilling wastes would be exempt from RCRA and are considered non-hazardous. Drilling mud containing less than 15,000 mg/l TDS can be disposed of on-site with the landowner's permission. The amount of waste generated are not expected to overwhelm the landfills in the area.

4.9.3.4.2 Operations

As with other drilling operations, there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as CH_4. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed and the drilling rig and associated equipment have been demobilized and replaced with a service rig. During the test, increasing pressures of CO_2 injection or borehole fluid would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig and a potentially unsafe condition for workers.

Solid wastes would be generated and would be transported by truck to a nearby permitted landfill. Other impacts would result from spills of waste during maintenance activities, including waste oil from generators, paint waste from construction activities and other solid wastes from construction activities. Impacts would also occur from the use of pesticides and herbicides during access and construction activities. The construction phase would consist of drilling wells into coal seams for injection of CO_2. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

4.9.3.5 Sequestration in Saline Formations

Sequestration in a saline water-bearing formation is similar to the sequestration in coal seam concept. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation.

4.9.3.5.1 Construction

The construction phase would consist of drilling wells into a saline geologic formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

4.9.3.5.2 Operations

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as methane. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed and the drilling rig and associated equipment have been demobilized and replaced with a service rig. During the tests, increasing pressures of CO_2 injection or borehole fluid would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig and a potentially unsafe condition for workers.

As with the CO_2 transportation project, one safety concern would be to maintain a dry stream of CO_2 so that carbonic acid would not form that could lead to pipe corrosion and potential catastrophic failure of the injection system.

4.9.3.6 Sequestration in Basalt Formations

Sequestration in a basalt formation is similar to sequestration in coal seams. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation.

4.9.3.6.1 Construction

The construction phase would consist of drilling wells into a basalt geologic formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

4.9.3.6.2 Operations

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as methane. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed and the drilling rig and associated equipment have been demobilized and replaced with a service rig. During the tests, increasing pressures of CO_2 injection or borehole fluid would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig and a potentially unsafe condition for workers.

As with the CO_2 transportation project, one safety concern would be to maintain a dry stream of CO_2 so that carbonic acid would not form which could lead to pipe corrosion and potential catastrophic failure of the injection system.

4.9.3.7 Terrestrial Sequestration – Reforestation

4.9.3.7.1 Construction

As described in Section 2.5, terrestrial sequestration projects generally would entail efforts to reclaim and restore degraded landscapes through the establishment of trees and grasses that will convert CO_2 into biomass. The projects would entail work activities similar to those of the agricultural and forestry industries.

> Herbicides and pesticides would not be used for terrestrial sequestration projects unless there is a clear benefit at that site, such as eliminating invasive plant species and insects that would cause substantial damage to project plantings.

Herbicides and pesticides may be used during clearing and site preparation to eliminate invasive plant species and insects that would reduce the chances of success for the tree and shrub planting. Chemical treatments should be selected according to the site conditions and the needs of the project. Herbicides and pesticides would not be used unless there would be a clear benefit to the project at that specific site. For example, some pine forests are highly susceptible to tree damage from pine beetle infestation. Insecticide spraying to control pine beetles is not usually undertaken because of the vast size of the forest areas that are vulnerable to pine beetles and the prohibitive costs for treating the forest. However, the areas for CO_2 sequestration would be smaller in size and control of pests would be advisable to protect the reforestation investment. Workers would be trained in the proper use of the chemicals, safe storage, and the proper disposal of unused chemicals.

Fertilizers may be used initially to help the plants become established. The types of fertilizer used would be largely site-dependent.

Equipment used to prepare and plant the areas to be reforested would use fuel for internal combustion engines such as diesel. The diesel fuel would be stored in above-ground tanks with secondary leak/spill containment. A SPCC Plan would be prepared to address the spills or leaks of fuels or other liquids.

During the site preparation phase, dead vegetative material (slash) may be collected and composted for future use as a soil supplement on areas that are lacking in organic material such as mine spoil or overburden areas. Slash would not be burned because that would be counterproductive to the CO_2 sequestration efforts by releasing more carbon into the atmosphere.

Other wastes would include used lubricating oil and sanitary wastes. These wastes would be collected and sent to permitted facilities for treatment or disposal.

4.9.3.7.2 Operations

The operational phase of the reforestation project would consist of monitoring the growth of the forest stands, replacing dead seedlings, evaluating the need for additional applications of herbicides and/or pesticides, and measuring the performance (growth rate, percent land cover, mean trunk diameter, etc) of the forest stands.

In general, the operational phase would create a lower impact related to the generation of wastes because there would be less activity overall, less use of heavy equipment, and lower usage of pesticides, herbicides and fertilizers.

4.9.3.8 Co-Sequestration of H_2S and CO_2

Materials and waste management impacts associated with the co-sequestration of CO_2 with H_2S from sour gas fields or IGCC plants generally would be similar to those described for geologic sequestration of CO_2 in oil and gas reserves or saline formations. The amount and types of materials used and wastes generated would be roughly the same for construction phase and operations phase, respectively. However, the amounts of materials and wastes would generally be a function of the quantity of CO_2 and H_2S that would be placed into storage. One exception would be the possible need for one or more pipelines to collect H_2S from a sour gas field or an IGCC plant. The waste treatment and disposal systems for similarly sized CO_2 geologic sequestration facilities would be roughly the same as for a CO_2 and H_2S geologic sequestration facility handling the same volume of gas.

4.9.4 Mitigation of Potential Adverse Impacts

The following measures are recommended to mitigate potential adverse impacts of sequestration technologies due to materials used and wastes that would be generated:

4.9.4.1 Project Planning and Design

- Determine if less hazardous materials can be substituted in the construction or operation of projects.

- Prepare permit applications and secure permits for any hazardous waste that would be generated.

- If hazardous materials would be used in sufficient quantities to trigger the 112r requirements of the Clean Air Act (CAA) Amendments, confer with the local emergency planning committee early in the planning process to establish a dialogue, explain the proposed facility, and learn how the emergency plan can be amended to address the new facilities. Observe the other requirements of the EPCRA and Section 112r of the CAA Amendments and prepare a RMP as required.

- Establish an effective monitoring and alarm system to detect CO_2 leaks from pipelines, valves, and other equipment.

- Prepare a SPCC plan for any fuel or oil storage tanks that would have sufficient capacity to trigger an SPCC plan under the federal CWA.

- Prepare a plan of operations for the well drilling phase that defines the project including: how drilling mud and cuttings will be handled.

4.9.4.2 Construction

- Determine if construction materials are available that meet EPA Affirmative Procurement Guidelines. Determine if construction refuse (concrete, metal, asphalt) can be recycled.
- Provide drilling mud retention ponds.
- Install and use leak detection or monitoring system for hydraulic fluids and lubricating oils on drill rigs.
- Prepare a safety information center in the site office where employees can review material safety data sheets, and other information that will promote a safe work place.
- Provide personal protective equipment to all employees that work with hazardous materials and wastes as necessary.
- Empower all employees to stop work if unsafe working conditions are observed.
- Comply with DOE materials and waste management-related directives as they apply to the project.

4.9.4.3 Operation

- Dispose of all hazardous, solid, or industrial wastes according to federal, state and local regulations.
- Implement the CO_2 monitoring and alarm system on pipelines, valves, and equipment. The system should include a means of periodically testing the system to ensure that it is in proper working order.
- Use systems/components that recycle process water whenever feasible.
- Prepare a safety information center in the site office where employees can review site safety plans, material safety data sheets, and other information that will promote a safe work place.
- Implement a system to respond to spills of hazardous materials or waste including reporting the spill to the correct authority, providing appropriate means of cleaning up spills, and properly disposing of the resulting waste.
- Comply with DOE materials and waste management-related Directives as they apply to the project.

4.9.5 Summary of Potential Impacts

Table 4-25 provides an overall qualitative assessment of potential impacts to materials and waste management for each sequestration technology.

Table 4-25. Potential Impacts of Program Technologies on Materials and Waste Management

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H2S
Solid waste	○	·	·	·	·	·	·	·
Hazardous waste	○	·	·	·	·	·	·	·
Hazardous materials	○	·	·	·	·	·	·	·

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

4.10 HUMAN HEALTH AND SAFETY

This section describes the potential impacts to human health and safety that could occur during the implementation of carbon sequestration technologies. Baseline health and safety information as it relates to sequestration technologies are described in Section 3.10. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.10.1 Impact Considerations

Potential impacts on human health and safety have been assessed using the general criteria outlined below and the impact definitions in Section 4.1.1. Short-term impacts for human health and safety are defined as impacts occurring during the construction timeframe or the results of isolated and temporary mishaps. Localized impacts for human health and safety are defined as those occurring within the project footprint.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Conflict with federal, state, or local regulations or DOE orders for the handling, packaging, storage, transport, or disposal of hazardous and radioactive materials and/or wastes.
- Conflict with adopted emergency response plans.
- Create unsafe conditions or expose employees and the public to situations that exceed health standards or present an undue risk of health-related accidents.
- Cause an increase in hazard quotient or cancer risk to the public.

In general, impacts on human health and safety from the implementation of sequestration technologies would be related to the number of workers that would be employed during the construction and operation phases of proposed facilities and the proximity to members of the public outside the boundaries of the proposed facilities. Impacts would be different and would depend on the technologies that would be used for sequestration projects.

Another aspect of human health and safety for carbon sequestration projects would be the potential for CO_2 inhalation accidents by workers. There are numerous documented cases of industrial workers being asphyxiated (deprived of normal breathing air) due to an undetected leak in process equipment, pipeline, or gas transfer point. Severe cases are fatal while non-fatal accidents can cause permanent brain injury due to lack of oxygen being delivered to the brain.

Unlike natural gas, CO_2 is odorless, and odorizers are not commonly added to CO_2 in pipelines the way natural gas is odorized with methyl mercaptan. Also, CO_2 is heavier than ambient air and will settle into low lying areas of the terrain including basements, and below-grade work areas. The gas can remain in these areas for a substantial period of time until the CO_2 is displaced with normal air through wind action or by other ventilation.

> CO_2 is odorless and heavier than air. It will settle into low lying areas and may remain for a substantial period of time until it is displaced by wind action or other ventilation.

4.10.2 Regulatory Framework

OSHA and the Compressed Gas Association have issued guidance for the safe handling of compressed CO_2 based on experience in the workplace and by investigations of accidents.

OSHA and an industry group, the Compressed Gas Association (CGA), have issued guidance for the safe handling of compressed CO_2 based on experience in the workplace and by investigation of accidents.

Worker exposure limits for CO_2 are listed below.

- OSHA General Industry Permissible Exposure Limit (PEL): 5,000 ppm, 9,000 mg/m3 time weighted average (TWA).
- OSHA Construction Industry PEL: 5,000 ppm, 9,000 mg/m^3 TWA.
- American Conference of Governmental Industrial Hygienists Threshold Limit Values (ACGIH TLV): 5,000 ppm, 9,000 mg/m^3 TWA; 30,000 ppm, 54,000 mg/m^3 short term exposure limit (STEL).
- National Institute for Occupational Safety and Health Recommended Exposure Limits (NIOSH REL): 5,000 ppm TWA; 30,000 ppm short term exposure limit.

Threshold Limit Values (TLVs) are determinations made by the American Conference of Governmental Industrial Hygienists. They represent the opinion of the scientific community that has reviewed the data described in the documentation, that exposure at or below the level of the TLV does not create an unreasonable risk of disease or injury.

Pipeline transportation of CO_2 became subject to the U.S. Office of Pipeline Safety in 1988 when an amendment to the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 100-561; October 31, 1988), gave DOT authority to regulate pipeline facilities that transport CO_2.

4.10.2.1 CO_2 Risk to the Public

Another human health risk is for members of the public to be exposed to CO_2 due to a rapid release of a large quantity of CO_2. Such a rapid release is considered to have a very low probability of occurrence based on the following considerations.

- Siting criteria for future geologic storage of CO_2 would include geologic conditions that are less likely to have leaks develop due to the confining layers above the formation that would receive the CO_2
- Siting criteria for future geologic storage of CO_2 would require the facility be located in a remote area, separated from cities or towns by many miles
- Monitoring and verification of operational geologic storage facilities would be conducted on a scheduled basis to detect leakage long before it would reach the earth's surface and potentially displace atmosphere essential for human life
- Real-time monitoring of CO_2 at the surface above geologic storage facilities so that an evacuation of personnel and nearby residents could be initiated if conditions warrant such action.

DOE's plan for managing risk at CO_2 geologic storage facilities is more fully explained in the fact sheet, *Risk Assessment for Long-Term Storage of CO_2 in Geologic Formations* (DOE, 2005a). Historic releases of CO_2 that caused hundreds of lives to be lost, the most notable example being the one at Lake

Nyos in Western Africa, are rare and have been due to natural processes related to recently active volcanic geologic formations. Recently active volcanic formations would not be considered suitable for CO_2 storage.

CO_2 exposure standards for the general public have not been developed.

CO_2 pipelines have been operating with few accidents for more than a decade. Although the safety record is good, with no reported accident-related injuries or fatalities (see Section 2.7), some safety guidelines are available for the public to help them identify and report a leak and help promote CO_2 pipeline safety, as listed below:

- Call the pipeline owner before digging near a pipeline;
- Listen for hissing or a roaring sound;
- Look for a white cloud, fog, or ice, or unusual blowing of dirt of dust;
- Observe dying plants amid healthy ones;
- Notice persistent bubbles in water; and
- Leave the area of a potential leak and call the pipeline company at the number provided on the pipeline marker. (Kinder Morgan, 2005)

More detailed information about CO_2 pipeline safety can be found at the Kinder Morgan website, www.kindermorgan.com/ehs/pipeline_safety/. Kinder Morgan is a company that operates a CO_2 pipeline in New Mexico and Texas.

4.10.2.2 CO_2 Risks to the Natural Environment

Potential risks to the environment include injury to vegetation or wildlife. One example of a direct impact to vegetation is the possible release of CO_2 into the soil before it would reach the atmosphere. The porous nature of many soil types enables the soil to absorb large volumes of CO_2 that otherwise would be occupied with gases from the atmosphere. This condition can cause trees and shrubs to die from lack of oxygen supplied through the root system. Such a condition was documented at the Mammoth Lakes area of California in 1989 in which a stand of trees more than 100 acres in size was found to have died due to CO_2 displacement of oxygen in the soil. Although the Mammoth Lakes phenomenon was caused by a natural release of CO_2, a similar release of CO_2 could potentially occur due to leakage from a geologic repository (DOE, 2005a).

> Naturally-occurring CO_2 releases have contributed to both plant and animal mortality.

An incident in Yellowstone National Park of injury and death to wildlife by naturally-occurring release of CO_2 and H_2S gases was documented in 2004 (Heasler and Jaworowski, 2004). Five bison were found to have been exposed to fatal levels of CO_2 and H_2S from a release of gases at the Norris Geyer Basin. The release of these gases, combined with extreme cold and lack of wind that limited the dispersion of the gases, created a hazardous atmosphere. Although this instance of injury to wildlife is from a volcanic area, the possibility of similar injury to wildlife is conceivable at a sequestration facility if a catastrophic release of CO_2 and H_2S were to occur.

4.10.2.3 Human Health Risks of Associated with a H_2S Release

Hydrogen sulfide (H_2S) is a toxic gas that sometimes occurs naturally in coal beds along with methane. H_2S is a component of uneconomic natural gas deposits known as "sour gas." H_2S has an odor of rotten eggs. The smell is pronounced at first exposure, but the gas quickly suppresses the sense of smell.

Exposure Limits

- OSHA Permissible Exposure Limit (PEL) for General Industry: 29 CFR 1910.1000 Z-2 Table -- Exposures shall not exceed 20 ppm (ceiling) with the following exception: if no other measurable exposure occurs during the 8-hour work shift, exposures may exceed 20 ppm, but not more than 50 ppm (peak), for a single time period up to 10 minutes.

- OSHA Permissible Exposure Limit (PEL) for Construction Industry: 29 CFR 1926.55 Appendix A -- 10 ppm, 15 mg/ m^3 TWA.

- OSHA Permissible Exposure Limit (PEL) for Maritime: 29 CFR 1915.1000 Table Z-Shipyards -- 10 ppm, 15 mg/ m^3 TWA.

- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Value (TLV): 10 ppm, 14 mg/ m^3 TWA; 15 ppm, 21 mg/ m^3 STEL.

- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limit (REL): 10 ppm, 15 mg/m^3 Ceiling (10 Minutes).

The most likely exposure scenario is for H_2S to be encountered during well drilling and the gas reaching the surface as well fluids circulate. Another, less likely scenario, would be for a large buildup of pressure in a geologic formation that would cause a well blowout during drilling and release of H_2S. The conditions for either release of H_2S are rare and would present a risk to workers at the drill rig. H_2S is heavier than air, like CO_2, so that it is likely to pool in low lying areas or basements of buildings. H_2S accumulation in tanks or confined spaces is a distinct hazard that warrants special procedures for safe entry if H_2S is suspected.

Several DOE directives would relate to human health and safety aspects of carbon sequestration projects as listed in Table 4-26.

Table 4-26. DOE Health and Safety Directives

Directive Number	Title	Purpose
DOE O 231.1A	Environment, Health and Safety Reporting	To ensure timely collection, reporting, analysis, and dissemination of information on environment, safety, and health issues as required by law or regulations or as needed to ensure that the DOE and National Nuclear Security Administration (NNSA) are kept fully informed on a timely basis about events that could adversely affect the health and safety of the public or the workers, the environment, the intended purpose of DOE facilities, or the credibility of the Department.
DOE P 411.1	Safety Functions, Responsibilities and Authorities Policy	The DOE has the responsibility to ensure that operations at its facilities are conducted safely. The purpose of this policy and the associated manual is to define the DOE safety management functions, responsibilities and authorities to ensure that work is performed safely and efficiently. This policy statement succinctly defines the Department's expectation regarding DOE employees' responsibilities for safety management. It does not establish any new requirements.

Directive Number	Title	Purpose
DOE O 440.1A	Worker Protection Management for DOE Federal and Contractor Employees	To establish the framework for an effective worker protection program that will reduce or prevent injuries, illnesses, and accidental losses by providing DOE federal and contractor workers with a safe and healthful workplace.
DOE O 450.1	Environmental Protection Program	To implement sound stewardship practices that are protective of the air, water, land, and other natural and cultural resources impacted by DOE operations and by which DOE cost effectively meets or exceeds compliance with applicable environmental; public health; and resource protection laws, regulations, and DOE requirements.
DOE 5480.4	Environmental Protection, Health, Safety and Health Protection Standards	To specify and provide requirements for the application of the mandatory ES&H standards applicable to all DOE and DOE contractor operations, to provide a listing of reference ES&H standards; and to identify the sources of the mandatory and reference ES&H standards.

Source: DOE, 2005.

Compliance with these DOE directives may be required as part of the cost-sharing agreement between DOE and the project proponent even though the facilities would not be owned by DOE nor staffed by DOE or contractor employees.

One element of protection of the public health and safety is the development of emergency response plans in local communities. Such plans define how an emergency would be handled by fire departments, police, and workplace emergency responders should a large emergency situation arise, such as an industrial fire, unexpected release of chemicals, or explosion that would place the community at risk. At this early stage of planning, the locations of proposed facilities are not known and the status of a site-specific emergency response plans cannot be determined. However, it is assumed that the proposed facility management would initiate a dialogue with local community leaders and amend the local emergency response plan to address the new facility.

Information about hazardous materials used at any work site would be made accessible to workers and members of the pubic through the posting of MSDS that explain the hazards that are posed by use of the material, personal protective equipment that should be worn when the material is used, and other precautionary measures.

4.10.3 Generalized Construction and Operational Impacts of Technologies

4.10.3.1 Post-combustion Capture

Post-combustion capture projects would be retrofitted to existing, or added to proposed, fossil fuel combustion facilities or comparable industrial processes. The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries, such as the power generation industry (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

Most processes available for post-combustion CO_2 capture, such as the use of sorbents or separation membranes, would not introduce features that have unknown or substantially more hazardous materials when compared to the features of an existing or proposed combustion power plant. Wastes that would be produced such as spent carbon from amine filter beds and disposable filter cartridges can be disposed of safely without unusual risk to workers or members of the public.

4.10.3.2 CO_2 Compression and Transport

The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The gas compression component of the project presents risks to workers from a possible catastrophic failure of the compressor. Several injuries and fatalities have been reported in compressor stations that are used to convey gases in pipelines. This is more of a concern when corrosive gases are being compressed and transported in a pipeline such as some types of natural gas before being processed in a gas sweetening plant. However, the purity of CO_2 must be maintained because CO_2 can combine with water to form carbonic acid and create a corrosive compound.

Similarly, the CO_2 storage tank and piping component of this project includes certain risks to workers due to the operations of equipment under high pressure conditions. The equipment is part of a category know as pressure vessels (OSHA, 2005). Several instances of catastrophic failure or pressure vessels have resulted in injuries to workers and in some cases fatalities. Pressure vessel accidents are rare.

Over a 10-year period (1995-2005), 12 incidents were reported for CO_2 pipelines. The sample size for CO_2 pipelines was small compared to those for natural gas and hazardous-liquids transmission, and it is reasonable to suggest that, statistically, the number of incidents involving CO_2 should be similar to those for natural gas transmission (Barrie et al., 2004).

As described in Section 2.5, CO_2 can be transported from compression facilities to sequestration sites via compressed gas pipeline or via commercial refrigerated tank trucks. It has been assumed that a cost-effective commercial scale project would likely provide conveyance by pipeline. However, CO_2 could be transported in tank trucks instead of a pipeline. Truck transportation would present an additional risk of traffic accidents during the transportation of the gas.

Human health risks to the general public would primarily be in the form of a potential pipeline accident that would create a release of CO_2 into the air at a location away from the compressor station. These risks would be greatly reduced through adopting safety and operating procedures commonly in place for gas processing facilities and pipelines. Controls on the pipeline operation would be used to detect a sudden loss of pressure to identify a large leak. Small leaks could be detected and prevented by periodic pipeline inspection and monitoring.

4.10.3.3 Sequestration in Coal Seams

The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The construction phase would consist of drilling wells into coal seams for injection of CO_2. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews. Safety practices that would help to minimize worker injuries and impacts to the environment are listed in Section 4.10.4.

As with other drilling operations, there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as CH_4. Precautions would be taken to avoid a well blow-out or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed. During the test, increasing pressures of CO_2 injection would be applied and the results would be measured in the surrounding monitoring wells and the injection well.

Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig that would pose a potentially unsafe condition for workers.

The operational phase of coal seam sequestration would require fewer workers and would pose a lower hazard than the construction phase. As with the CO_2 transportation project, one safety concern would be to maintain a pure stream of CO_2 so that carbonic acid would not form that could lead to pipe corrosion and potential catastrophic failure of the injection system.

Tracers are sometimes injected into the CO_2 stream so that measurements can be made about its transport within the formation. Tracer levels are measured in monitoring wells to determine their distribution in area and time. The compounds used as tracers are typically nontoxic and will degrade within the formation over time. Common tracers include fluorescein sodium dyes, ammonium nitrate or fertilizer, ammonium thiocyanate, and lower molecular-weight alcohols such as methanol and isopropanol. The specific tracer(s) to be used, if any, would be evaluated and addressed during the site-specific NEPA process.

4.10.3.4 Sequestration in Depleted Oil and Gas Reserves

The mechanics of sequestration in depleted oil and gas reserves or EOR are similar to that of coal seam sequestration - both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation. The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The construction phase would consist of drilling wells into depleted oil deposits or reworking existing wells if they are deemed suitable to support the injection of CO_2. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews. Safety practices that would help to minimize worker injuries and impacts to the environment are listed in Section 4.10.3.

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as methane. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed. During the test, increasing pressures of CO_2 injection would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig that would pose a potentially unsafe condition for workers.

The operational phase of sequestration would require fewer workers and would pose a lower hazard than the construction phase. As with the CO_2 transportation project, one safety concern would be to maintain a pure stream of CO_2 so that carbonic acid would not form that could lead to pipe corrosion and potential catastrophic failure of the injection system.

4.10.3.5 Sequestration in Saline Formations

The mechanics of sequestration in a saline geologic formation is similar to that of sequestration in coal seams. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation. The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The construction phase would consist of drilling wells into a saline geologic formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as CH_4. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed. During the test, increasing pressures of CO_2 injection would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig that would pose a potentially unsafe condition for workers.

The operational phase of saline formation sequestration would require fewer workers and would pose a lower hazard than the construction phase. As with the CO_2 transportation project, one safety concern would be to maintain a pure stream of CO_2 so that carbonic acid would not form that could lead to pipe corrosion and potential catastrophic failure of the injection system.

4.10.3.6 Sequestration in Basalt Formations

The mechanics of sequestration in a basalt geologic formation is similar to that of sequestration in coal seams. They both consist primarily of a network of wells and piping systems for injecting CO_2 into a geologic formation. The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The construction phase would consist of drilling wells into a basalt geologic formation. Monitoring wells would also be drilled into the formation to measure the concentrations of CO_2, CH_4, and water. This would be similar to well drilling activity in the oil and gas industry. Standard safety precautions would be observed by the work crews.

As with other drilling operations there would be a potential of drilling into a pressurized formation that could contain a flammable gas such as CH_4. Precautions would be taken to avoid a well blowout or venting dangerous gases in work areas. After the injection well is completed, tests would be conducted on the formation where the well is completed. During the test, increasing pressures of CO_2 injection would be applied and the results would be measured in the surrounding monitoring wells and the injection well. Under high pressure, equipment could fail and allow a sudden release of CO_2 at the drill rig that would pose a potentially unsafe condition for workers.

The operational phase of basalt aquifer sequestration would require fewer workers and would pose a lower hazard than the construction phase. As with the CO_2 transportation project, one safety concern would be to maintain a pure stream of CO_2 so that carbonic acid would not form which could lead to pipe corrosion and potential catastrophic failure of the injection system.

4.10.3.7 Terrestrial Sequestration

As described in Sections 2.5, terrestrial sequestration projects generally would entail efforts to reclaim and restore degraded landscapes through the establishment of trees and grasses that will convert CO_2 into biomass. The projects would entail work activities similar to those of the agricultural and forestry industries. Work related injuries are generally higher among agricultural and forestry workers than the U.S. private workforce in general.

The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

Herbicides and pesticides may be used during clearing and site preparation to eliminate invasive plant species and insects that would reduce the chances of success for the tree and shrub planting. The particular herbicides and pesticides have not been identified at this early stage in the planning process. Human health impacts to workers would be limited by workers receiving training in the proper use and storage of the chemicals, using personal protective equipment, and proper disposal or recycling of unused chemicals.

4.10.3.8 Co-Sequestration of H_2S and CO_2

Impacts on human health and safety associated with the co-sequestration of CO_2 with H_2S from sour gas fields or IGCC plants generally would be similar to those described for geologic sequestration in oil and gas reserves or saline formations. The number of workers would be roughly the same although the potential hazards faced by workers would be greater for co-sequestration due to the presence of H_2S in the process stream. Workers would need to be prepared to protect themselves against the toxic effects of H_2S and the oxygen displacing effects of CO_2 should a leak occur.

The frequency of injuries for construction and operations workers can be estimated based on accident and injury rates in similar industries (BLS, 2004). Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment.

The estimated rate of worker injuries would be higher for the co-sequestration of CO_2 with H_2S from IGCC plants than from sour gas fields due to a larger workforce during operations. For co-sequestration projects, corrosion of pipes and components may become an important factor for potential equipment failure that historic accident data for the general work industry does not recognize.

Equipment preventative maintenance is always important to help establish a safe working environment. Maintenance procedures become even more important when corrosive process chemicals or products are used.

4.10.4 Mitigation of Potential Adverse Impacts

The following measures are recommended to mitigate potential adverse impacts of carbon sequestration technologies on human health and safety:

4.10.4.1 Project Planning and Design

- Prepare a comprehensive safety program that addresses the construction and operations phases of the project. Ideally that plan would include a training plan, regular safety meetings, and an employee safety-awareness program.

- Confer with the local emergency planning committee early in the planning process to establish a dialogue, explain the proposed facility, and learn how the emergency plan can be amended to address the new facilities. Observe the other requirements of the EPCRA and Section 112r of the CAA amendments.

- Since the sudden release of a large quantity of CO_2 can have ground-level impacts on nearby flora, fauna, and humans, monitoring for leaks in and around pipelines and around injection points is an important consideration of any system design. Transmission piping and wells should be located to allow for adequate dispersion of CO_2 (away from populated areas) in the event of an accidental release.

> Transmission piping and wells should be located to allow for adequate dispersal of CO_2 away from populated areas in the event of an accidental release.

- Design an effective monitoring and alarm system to detect CO_2 leaks from pipelines, valves, and other equipment.

- Prepare a Risk Management Plan (RMP) if any of the facilities would use chemicals in quantities sufficient for the facility to become subject to the risk management provisions of Section 112r of the CAA amendments.

4.10.4.2 Construction

- Establish a culture of safety at the work site including daily safety meetings and a site safety plan that focuses on construction activities.

- Prepare a safety information center in the site office where employees can review site safety plans, MSDS, and other information that will promote a safe work place.

- Provide personal protective equipment to all employees that is appropriate for the hazards that would be encountered in the workplace.

- Empower all employees to stop work if unsafe working conditions are observed.

- Encourage workers to notice unsafe work practices and make improvements that will lead to a safer work site.

- Comply with OSHA requirements and DOE safety-related directives as they apply to the project.

- For drilling operations, adhere to guidelines for safe drilling practices including: avoidance of overhead power lines and other energized electrical components, assurance that emergency shut-down devices are in proper working order, observance of precautions on MSDS for drilling fluids, usage of personal hearing protection when sound levels justify such precautions, detection of hazardous gases (including CO_2 and H_2S), and reporting unsafe working conditions to the rig supervisor and discontinuing operations until safe conditions are restored.

4.10.4.3 Operation

- Prepare and apply a safety plan that a focuses on the operational aspects of the facilities.

- Implement a CO_2 and H_2S monitoring and alarm system on pipelines, valves, and equipment. The system should include a means of periodically testing the system to ensure that it is in proper working order.

- Implement a reservoir monitoring and data collection process to evaluate: formation pressures, leaks to overlying groundwater aquifers, seismic activity, well-bore integrity and surface leaks.

- Prepare a safety information center in the site office where employees can review site safety plans, material safety data sheets, and other information that will promote a safe work place.

- Provide personal protective equipment to all employees that is appropriate for the hazards that would be encountered in the workplace.

- Empower all employees to stop work if unsafe working conditions are observed.

- Encourage workers to notice unsafe work practices and make improvements that will lead to a safer work site.

- Comply with OSHA requirements and DOE safety-related directives as they apply to the project.

4.10.5 Summary of Potential Impacts

As stated above, human health and safety would be a primary consideration at all of the sites. A site-specific risk assessment for CO_2 releases and a comprehensive safety program for workers and the community should be performed during the project planning phase.

Table 4-27 provides an overall qualitative assessment of potential impacts to human health and safety for each sequestration technology. Because of the inherent uncertainty related to the probability of a large scale CO_2 release at a site, these impact levels do not take into consideration a large and sudden leak/release of CO_2 from a geologic reservoir.

Table 4-27. Potential Impacts of Program Technologies on Health and Safety

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Toxic and hazardous materials	○	·	·	·	·	·	·	⦿
Operational hazards	○	○	·	·	·	·	·	⦿

Key: · Negligible Impact, ○ Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

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4.11 SOCIOECONOMICS

This section describes the potential impacts in terms of socioeconomics that could occur during the implementation of carbon sequestration technologies. Baseline information on these subjects is provided in Section 3.11. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.11.1 Impact Considerations

The general criteria outlined below have been used as a basis for evaluating potential adverse impacts of carbon sequestration projects on socioeconomics.

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Displace existing population on a site selected for project.
- Substantially alter projected rates of population growth directly or indirectly in the area of influence.
- Cause demolition of existing housing on a site selected for a project.
- Adversely affect housing demand directly or indirectly in the area of influence.
- Displace existing businesses on a site selected for a project.
- Adversely affect local businesses and the economy directly or indirectly in the area of influence.
- Displace existing jobs on a site selected for a project.
- Adversely affect local employment or the workforce directly or indirectly in the area of influence.
- Adversely affect community services (police, fire, health care, schools) directly or indirectly in the area of influence.
- Conflict with local and regional management plans for community services.
- Create the potential for significant and disproportionate adverse effects on low-income populations in the area of influence.

4.11.2 Regulatory Framework

Potential socioeconomic and environmental justice impacts of a project are generally the subject of federal NEPA documents and are not governed by laws or regulations. Executive Order Number 12898 provides that "*each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations*" (The White House, 1994). In its guidance for the consideration of environmental justice under NEPA, the CEQ defines a "minority" as an individual who is American Indian or Alaskan Native, Black or African American, Asian, Native Hawaiian or Pacific Islander, Hispanic or Latino (CEQ, 1997). The statistics on minorities presented in Chapter 4, Section 4.11 are based on this definition. The CEQ also defines a "minority population" as one where either the percentage of minorities in the affected area exceeds 50 percent, or the percentage of minorities in the affected area is meaningfully greater than the percentage of minorities in the general population or other appropriate unit of geographic analysis (CEQ, 1997).

The CEQ guidance further recommends that low-income populations in an affected area should be identified using the U.S. Census Bureau's Current Population Reports, Series P-60 on Income and Poverty (CEQ, 1997). The individual poverty rates included in Chapter 4, Section 4.11 were obtained from data (Census 2000 Summary File 3) consistent with that source.

The basic steps for evaluating the environmental justice impacts of a Proposed Action under NEPA, consistent with the CEQ guidance and DOE recommendations (DOE, 2004), are the following:

- Determine whether the proposed action or an alternative would have a significant adverse impact on the affected area. Consider all potential impacts (e.g., health effects, air quality, water quality, cultural resources, cumulative impacts).

- Determine whether low-income or minority populations exist based on a comparison of the percentages of these individuals in the affected area of the proposed action with the percentages in the wider geographic area or representative general population.

- Determine whether there would be any significant adverse impacts to minority and low-income populations that would appreciably exceed impacts to the general population or other appropriate comparison group. Consider whether minority and low-income populations would have different ways than the general population of being affected by a proposed action or alternative.

> Because utility costs generally represent a greater proportion of non-discretionary expenditures for low-income consumers, increases in average monthly electric bills associated with the cost of carbon sequestration activities may affect these consumers adversely and disproportionately.

Most direct socio-economic impacts from the implementation of sequestration technologies would be related to the siting, construction, and operation of proposed projects and facilities within regions, states, and local communities. Indirect or induced impacts may result from changes in national, regional, state, and local economies caused by the implementation of sequestration technologies. Most potential impacts on environmental justice would be associated with the site selection process. However, impacts on local economies and utility costs caused by the implementation of sequestration technologies could have implications for environmental justice.

The GCCI calls for an 18 percent reduction in the carbon intensity of the U.S. economy by 2012. In the process of attaining this goal, the President and DOE intend that technologies and projects implemented under the Program would result in less than a 10 percent increase in the cost of energy services for advanced power systems and less than a 20 percent increase for traditional combustion facilities. If energy providers implementing sequestration projects were to pass the full costs of the technologies on to consumers, the average monthly electric bills for their customers could potentially increase by 10 to 20 percent after the technologies were implemented. Based on the national average monthly electric bills in 2002, customers could experience increases on average comparable to those summarized in Table 4-28.

Table 4-28. Potential Increase in Average Monthly Electric Bill by Sector to Pay for Carbon Sequestration Technologies (2002 Baseline)

Customer Sector	National Average Monthly Bill*	Average Increase in Monthly Bill (10%)	Average Increase in Monthly Bill (20%)
Residential	$76.74	$7.67	$15.35
Commercial	$478.41	$47.84	$95.68
Industrial	$6,647.01	$664.70	$1,329.40

Source: EIA, 2002.

Because utility costs generally represent a greater proportion of non-discretionary expenditures for low-income consumers than for higher income consumers, increases in average monthly electric bills by 10 to 20 percent as indicated in Table 4-28 may affect these consumers adversely and disproportionately. On the other hand, some economists predict that the future costs associated with global warming and adaptation impacts would be higher than the costs of implementing sequestration projects. But, whether such costs might affect low-income populations disproportionately would depend on how the free market or the government responds to the increased demands on energy and economic systems caused by climate change and adaptation requirements. Therefore, sponsors of specific projects to implement sequestration technologies should carefully evaluate the manner in which the local share of project costs would affect customers in the service area and determine whether the method of distributing these costs would have a disproportionate adverse impact on low-income populations.

4.11.3 Generalized Siting and Operational Impacts of Technologies

4.11.3.1 Post-combustion Capture

A post-combustion capture project would typically be located within the site boundary of an existing power plant or other industrial source facility. Therefore, adding a CO_2 capture process to an existing industrial site would not affect local population growth, displace housing or businesses, cause job losses, require expansions in community services, or otherwise affect demographic and socioeconomic conditions. An exception might occur if the new process required a significant expansion of the facility property or would otherwise introduce features (increased air emissions, noise, hazardous materials, etc.) that would adversely affect adjacent housing, businesses, and community services. In such case, or in the event that a post-combustion capture process would be associated with a proposed new industrial facility, the environmental review for the new facility should address all site-specific impacts on socioeconomic resources based on criteria in Section 4.11.1.

Most processes available for post-combustion CO_2 capture, such as the use of sorbents or separation membranes, would not cause an increase in the demands on local fire and emergency response services when compared to the features of an existing or proposed fossil-fueled power plant. Therefore, the contributions of a CO_2 capture process to air emissions, hazardous materials, safety hazards, and other features already associated with a power plant or comparable industrial process would have negligible additional impacts on adjacent housing, businesses, and community services.

As further indicated in Section 2.5, additional manpower requirements for the operation of a representative CO_2 capture facility would be minor relative to the existing workforce. The addition of these positions would have a small beneficial effect on local employment and the economy in most communities.

Construction of required facilities would require a relatively large though short-term workforce. Hence, such projects would have beneficial short-term impacts on local economies.

4.11.3.2 CO_2 Compression and Transport

Generally, the addition of CO_2 compression facilities to an existing or proposed industrial site would not affect local population growth, displace housing or businesses, cause job losses, require expansions in community services, or otherwise affect demographic and socioeconomic conditions. An exception might occur if the new process required a significant expansion of the facility property or would otherwise introduce features (increased air emissions, noise, hazardous materials, etc.) that would adversely affect adjacent property owners and communities. In such case, or in the event that a post-combustion capture process would be associated with a proposed new industrial facility, the environmental review for the new facility would address all site-specific impacts on socioeconomic resources using criteria in Section 4.11.1.

Assuming that a cost-effective commercial-scale project would likely provide conveyance by pipeline, the principal aspect of a CO_2 compression and transport project that would affect housing, businesses, and community services is the potential need for easements and rights-of-way for underground CO_2 pipelines and access roads. Where practicable, these impacts can be minimized by utilizing easements already established for other utility pipelines and power transmission lines. Otherwise, new easements would be required, which would necessitate an assessment of site-specific impacts on local property owners and communities based on criteria Section 4.11.1. In the event that tank trucks would transport CO_2, the principal impacts on surrounding communities would be related to the numbers of trucks entering and leaving the respective compression and sequestration sites on a daily basis.

Because CO_2 is an inert, non-toxic gas, the establishment of easements for pipeline corridors would not necessarily impose significant restrictions on property owners and communities affected by the easements. However, the easements would generally require that the corridors remain cleared of large trees and be accessible for inspection and maintenance of the pipelines, that permanent structures may not be built within the easements, and that subsurface excavation may not occur. Appropriate negotiation of easements with property owners would ensure that they are compensated for the resulting limitations on the beneficial use of their properties.

The operation of CO_2 compression and transport facilities would create a small number of additional jobs at the facility. The addition of these positions would have a small beneficial effect on local employment and the economy in most communities.

Construction of pipeline facilities would require a relatively large though short-term workforce. Hence, such projects would have beneficial short-term impacts on local economies. Projects that would transport CO_2 by truck would have a negligible impact on local employment.

4.11.3.3 Sequestration in Coal Seams

Suitable coal seams closest to existing fossil-fueled power plants or other CO_2 sources would be the most promising candidates for the application of a pilot- or commercial-scale project initially. A host of economic considerations could affect site selection, including the feasibility of enhanced CBM recovery and the potential for future coal extraction from the seam by the holder of the mineral rights, the nature of the terrain, the accessibility of a proposed site, and the availability of suitable rights-of-way for conveyance corridors. A suitable coal seam must also have adequate containment capacity, including a sufficiently impervious caprock, to prevent the migration of injected CO_2 beyond the site boundary and its release above the ground surface in concentrations that could potentially affect adjacent property owners. The objective of storing CO_2 in a seam indefinitely may also preclude mineral extraction on adjacent properties. An appropriate method of MM&V should be selected to monitor the potential release of CO_2 beyond the target coal seam, including mechanisms and procedures to protect local residents in the event of unanticipated releases of CO_2. Hence, before selecting a suitable location for a coal seam sequestration project, an assessment of site-specific socioeconomic impacts would be required.

The most promising initial candidate sites for coal seam sequestration would include suitable coal seams in areas that have already been disturbed by activities during previous coal mining operations. It is anticipated that the siting of coal seam sequestration projects generally would not occur in urban jurisdictions. Therefore, sites chosen for coal seam injection and associated MM&V facilities most likely would not affect local population growth, displace housing or businesses, cause job losses, or require expansions in community services. Revenues from enhanced coalbed methane recovery associated with projects involving coal seam CO_2 sequestration may have a net beneficial impact on the local economy.

There would be some additional manpower required for the operation of a coal seam sequestration project. These operational manpower requirements would have a negligible effect on local employment and the economy. The construction of required facilities would have a beneficial short-term impact on local economies.

4.11.3.4 Sequestration in Depleted Oil and Gas Reserves

The most promising candidate locations initially for pilot-scale and commercial-scale sequestration would include depleted oil and gas reserves that are situated within close proximity of fossil fuel-fired power plants or other large CO_2 sources. A key factor that may influence the siting of sequestration projects in depleted oil reserves is the economic incentive offered by EOR. A suitable oil or gas reservoir must also have adequate containment capacity, including a sufficiently impervious caprock, to prevent migration of injected CO_2 beyond the site boundary and prevent its release above the ground surface in concentrations that could potentially affect adjacent properties. The objective of storing CO_2 in the reservoir indefinitely may also preclude mineral extraction on adjacent properties. An appropriate array of MM&V should be selected to monitor the potential release of CO_2 beyond the target reservoir, including mechanisms and procedures to protect local residents in the even of an unanticipated release of CO_2 at unsafe concentrations. Hence, before selecting a suitable location for an oil and gas reservoir sequestration project, an assessment of site-specific socioeconomic impacts would be required.

It is assumed that candidate sites will be situated on lands that have been substantially disturbed during years of oil and gas production and that the siting of sequestration projects generally would not occur in urban jurisdictions. Therefore, sites chosen for sequestration and associated MM&V facilities most likely would not affect local population growth, displace housing or businesses, cause job losses, or require expansions in community services. Revenues from EOR associated with CO_2 sequestration projects may have a net beneficial impact on the local economy.

Additional manpower would be required for the operation of an oil or gas field sequestration project. These operational manpower requirements would have a negligible effect on local employment and the economy. The construction of required facilities would have a beneficial short-term impact on most local economies.

4.11.3.5 Sequestration in Saline Formations

Although the surface facilities needed for sequestration in saline formations would be similar to those for sequestration in coal seams and depleted oil and gas reserves, saline formations would not necessarily involve lands that have been disturbed during prior resource extraction. A suitable saline formation must have adequate containment capacity, including a sufficiently impervious caprock, to prevent migration of injected CO_2 beyond the site boundary and its release above the ground surface in concentrations that could potentially affect adjacent property owners. An appropriate array of MM&V should be selected to monitor the potential release of CO_2 beyond the target reservoir, including mechanisms and procedures to protect local residents in the event of an unanticipated release of CO_2 in unsafe concentrations. The objective of storing CO_2 in the formation indefinitely may also preclude mineral extraction on adjacent properties. Hence, before selecting a suitable location for a saline sequestration project, an assessment of site-specific socioeconomic impacts would be required. Because saline sequestration projects generally would not occur in urban jurisdictions, such projects most likely would not affect local population growth, displace housing or businesses, cause job losses, require expansions in community services, or otherwise affect demographic and socioeconomic conditions.

These operational manpower requirements would have a negligible effect on local employment and the economy. The construction of required facilities would have a beneficial short-term impact on most local economies.

4.11.3.6 Sequestration in Basalt Formations

Although the surface facilities needed for sequestration in basalt formations would be similar to those for sequestration in coal seams and depleted oil and gas reserves, basalt formations would not necessarily involve lands that have been disturbed during prior resource extraction. A suitable basalt formation must have adequate containment capacity, including a sufficiently impervious caprock, to prevent migration of injected CO_2 beyond the site boundary and its release above the ground surface in concentrations that could potentially affect adjacent property owners over the short-term. Over the long-term, mineralization of the CO_2 is expected to reduce the chance of a CO_2 release from the formation. An appropriate array of MM&V should be selected to monitor the potential release of CO_2 beyond the target formation, including mechanisms and procedures to protect local residents in the event of an unanticipated release of CO_2 in unsafe concentrations. The objective of storing CO_2 in the formation indefinitely may also preclude mineral extraction on adjacent properties. Hence, before selecting a suitable location for a basalt sequestration project, an assessment of site-specific socioeconomic impacts would be required. Because basalt sequestration projects generally would not occur in urban jurisdictions, such projects most likely would not affect local population growth, displace housing or businesses, cause job losses, require expansions in community services, or otherwise affect demographic and socioeconomic conditions.

The additional operational manpower requirements associated with a project would have a negligible effect on local employment and the economy. The construction of required facilities would have a beneficial short-term impact on most local economies.

4.11.3.7 Terrestrial Sequestration - Reforestation

Terrestrial sequestration projects sponsored or supported by DOE generally would most likely involve efforts to reclaim and restore degraded landscapes through reforestation and afforestation that would convert CO_2 into biomass. The reclamation of degraded lands would have a net beneficial effect on demographic and socioeconomic conditions in most communities by improving open space utilization and potentially enhancing property values. Such projects generally would not alter local population growth, displace housing or businesses, cause job losses, or require expansions in community services, because candidate sites would include lands that have been degraded by prior extraction operations and that have not been developed for residential housing or businesses. If, however, a potential project were to alter a property in a manner that would adversely affect adjacent communities, an assessment of site-specific socioeconomic impacts would be required.

> Reclamation of degraded lands by reforestation is expected to have a net beneficial effect on socioeconomic conditions in most communities, by improving open space utilization and potentially enhancing property values.

Reforestation projects would not require fulltime personnel for continuous operation, because they would not create any industrial facilities. The activities involved in land reclamation and tree planting for such projects would employ small numbers of workers for less than a year, which would have a negligible impact on most local economies.

4.11.3.8 Co-Sequestration of H_2S and CO_2

Co-sequestration of H_2S and CO_2 generally would be similar to sequestration of CO_2 in coal seams, oil and gas reserves, and saline formations. The facilities and infrastructure would be comparable, however, different materials for pumps, compressors, and pipelines would be used to guard against the corrosive nature of the sour gas. Revenues from EOR associated with sequestration projects may have a net beneficial impact on the local economy. As with the aforementioned model projects, sites chosen for co-sequestration facilities most likely would not affect the local population, displace housing or businesses, cause job losses, require expansions in community services, or otherwise affect demographic and socioeconomic conditions. The construction of required facilities would have a beneficial short-term impact on most local economies.

4.11.4 Mitigation of Potential Adverse Impacts

The following measures are recommended to mitigate potential adverse socioeconomic impacts of carbon sequestration technologies:

4.11.4.1 Project Planning and Design

- Closely consider the extent to which the local share of costs for a proposed project would increase the cost of energy services to consumers. If the proposed project would result in greater than a 10 percent increase in the cost of energy services for customers of advanced power systems or greater than a 20 percent increase for customers of traditional combustion facilities, the cost increases might exceed the intentions of the President and DOE regarding the costs of attaining the GCCI goal. Substantial increases in energy costs to local consumers may affect low-income populations adversely and disproportionately, because utility costs often constitute larger percentages of the incomes and living expenses of such individuals.

- Determine whether the service area that would incur the increased cost of energy services to support the proposed project constitutes a low-income or minority population by the definitions and analyses described in Section 4.11.1. If so, determine whether these populations would be affected adversely and disproportionately by the increased cost of energy services to support the proposed project.

- Consider alternatives for distributing the anticipated increases in utility costs to support the proposed project, to mitigate the potential for adverse and disproportionate impacts on low-income populations.

- Plan for efficient use of the property and consolidation of infrastructure requirements as practical. Integrate site design elements with surrounding communities and provide appropriate buffer areas to minimize impacts on adjacent housing, businesses, and community services.

- If the project (e.g., post-combustion capture) would be located at an existing industrial facility, determine whether adequate, suitable space is available to accommodate new facilities without affecting established buffer areas or encroaching on adjacent properties.

- If the project will require the acquisition of new sites for facilities, avoid locations that may cause displacement of population, residential housing, or local businesses. Avoid locations that may adversely affect the range and capacity of community services (fire, emergency response, law enforcement, etc.).

- Determine whether low-income or minority populations exist in the area affected by a proposed project. If so, determine whether these populations would be adversely and disproportionately affected by the siting of project facilities and components as described in Section 4.11.1.

- Confer with local and regional authorities early during the site selection process to identify goals, plans, and policies pertaining to community services (fire, emergency response, law enforcement, etc.) that may be affected by the proposed project. Ensure that community services will be adequate to address the requirements of the project without adversely affecting the local tax base.

- Determine whether rights-of-way would be required for pipeline corridors, access roads, or other facilities. Identify established easements that may be available to accommodate additional pipelines or access roads in the proposed transmission corridor and minimize the need for new easements. If new rights-of-way will be required, ensure that all of the preceding recommendations are followed during planning for corridor alignments.

4.11.4.2 Construction

- Adhere to site plans and minimize the footprint of land area disturbance required for a proposed project, including permanent structures, roads, temporary structures, staging areas, and other features.

- Maintain buffer zones to minimize construction impacts on adjacent housing, businesses, and community services.

- Limit trucking operations for deliveries and removals to non-peak periods, while avoiding noise-sensitive times of day, to minimize traffic impacts on adjacent housing, businesses, and community services.

- Restrict construction activity to the least noise-sensitive times of day in accordance with local ordinances to minimize noise impacts on adjacent housing, businesses, and community services.

- Locate stationary construction equipment as far as practicable from property boundaries and adjacent housing, businesses, and community services.

- Require the implementation of noise suppression equipment and BMPs to reduce noise to acceptable levels at property boundaries of adjacent communities. For example, require sound-muffling devices on construction equipment that are no less effective than as provided on original equipment and ensure that devices are properly maintained.

- Implement BMPs for control of construction-related air emissions, erosion and sedimentation control, and habitat protection as described for other respective resources to minimize adverse impacts on adjacent housing, businesses, and community services.

- Reclaim and restore disturbed areas expeditiously in accordance with established landscaping plans for the project site upon completion of construction phases.

4.11.4.3 Operation

- Conduct facility operations within established local ordinances, as well as federal and state regulations, to minimize impacts on adjacent housing, businesses, and community services.

- Limit trucking operations for deliveries and removals to non-peak periods, while avoiding noise-sensitive times of day, to minimize traffic impacts on adjacent housing, businesses, and community services.

- Limit noise-emitting operations to the least noise-sensitive times of day in accordance with local ordinances to minimize noise impacts on adjacent housing, businesses, and community services.

- Require the implementation of noise suppression equipment and BMPs to reduce noise to acceptable levels at property boundaries of adjacent communities. For example, require sound-muffling devices on operational equipment that are no less effective than as provided on original equipment and ensure that devices are properly maintained.

4.11.5 Summary of Potential Impacts

Table 4-29 provides an overall qualitative assessment of potential impacts on socioeconomics for each sequestration technology. Construction and operation of sequestration facilities generally would have negligible to minor adverse impacts on demographic and socioeconomic conditions. Revenues from enhanced CBM recovery and EOR associated with sequestration in coal seams and oil reserves may cause net beneficial impacts for respective projects. Most projects would also have slight beneficial impacts on local employment resulting from construction and operation of required facilities.

Table 4-29. Potential Impacts of Program Technologies on Socioeconomics

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Population	·	·	·	·	·	·	·	·
Housing	·	·	·	·	·	·	·	·
Business and Economy	·	·	+	+	·	·	+	+
Employment	+	+	+	+	+	+	·	+
Community Services	·	·	·	·	·	·	·	·
Low-income population	O	O	·	·	O	O	·	·

Key: · Negligible Impact, O Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

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4.12 UTILITY INFRASTRUCTURE

This section describes the potential impacts to utility infrastructure that could occur during the implementation of carbon sequestration technologies. The utility infrastructure that could be affected by sequestration technologies are described in Section 3.12. Possible measures for avoiding or mitigating potential adverse impacts are also presented in this section.

4.12.1 Impact Considerations

A project or technology would be considered to have an adverse impact on the natural or human environment if any of its features or processes would:

- Adversely affect the capacity of public water utilities directly or indirectly.
- Require substantial extension of water mains involving offsite construction for connection with a public water source.
- Insufficient water supply capacity for fire suppression demands.
- Cause excessive fuel requirements.
- Adversely affect the capacity and distribution of local and regional energy suppliers.
- Require substantial extension of telecommunications utilities involving offsite construction for connection with the network.
- Adversely affect traffic volumes compared to existing capacities and traffic loads on roadways in the area of influence.
- Cause substantial alteration of traffic patterns or circulation movements.
- Conflict with local or regional transportation plans.
- Adversely affect rail traffic compared to existing capacities and loads on railways in area of influence.
- Conflict with regional railway plans.

In general, the implementation of sequestration technologies would be related to the infrastructure needs during the construction and operation phases of proposed facilities. Impacts would depend on the technologies that would be used for sequestration projects, size of the facilities, and location.

4.12.2 Regulatory Framework

Project developers should take into account federal, regional, and State environmental laws and regulations, Executive Orders, and Policy that may apply to the carbon sequestration projects. Some of these that relate to the utility infrastructure include:

- Safe Drinking Water Act (SDWA) of 1974 (42 USC § 300(f)) - This Act specifies a system for the protection of drinking water supplies through the establishment of contaminant limitations and enforcement procedures. The Act requires each state to adopt a program to protect wells within its jurisdiction from contamination. States have the primary responsibility to enforce compliance with national primary drinking water standards and sampling, monitoring, and notice requirements.

- UIC program (40 CFR Parts 144-147) – The UIC program was promulgated under the SDWA and regulates the injection of fluids in the subsurface. The regulations establish minimum requirements for UIC programs. Each state must meet these requirements in order to obtain primary enforcement authority for the UIC program in that State.

While federal and state highways and other roads, as well as freight railroad lines, could be utilized for a potential carbon sequestration project, it is too early in the planning process to specify which highways or railroads would be utilized. Therefore, particular requirements and potential impacts on transportation infrastructure would be determined during the site-specific planning and development stage for potential projects. Qualitatively, on a national and regional basis, potential carbon sequestration projects are anticipated to have negligible impacts on highways and railways. Such projects are not anticipated to require frequent and substantial shipments of materials or waste products by truck or rail during normal operations, and they are not expected to employ large numbers of workers in proximity to urban commuting areas.

While no new railroad lines would likely be developed for potential projects, the need for new access roads might arise in the course of detailed planning and site layout.

4.12.3 Generalized Siting and Operational Impacts of Technologies

4.12.3.1 Post-combustion Capture

Post-combustion capture projects require steam, electricity, water, and chemicals during operation. Since these projects would be built adjacent or in close proximity to existing industrial facilities that may already be generating and/or utilizing these utilities, the incremental impacts on the existing utility infrastructure would be minimal. Post-combustion capture technologies would be used to treat the exhaust from utility or industrial size boilers. Process steam requirements can be met by extracting steam at the required temperature and pressure from existing steam turbines as is typical in cogeneration applications. As described in Section 2.5, the electricity power requirements of the capture project are extremely small (< 5 MW) in comparison to either the host facility's generation capacity (e.g., 300 MW on commercial scale) or electricity available from the power grid. Therefore these projects are not expected to require any significant changes to existing or future electric transmission infrastructure. However, the parasitic energy requirement for CO_2 capture and compression would be a concern to the energy provider in terms of meeting their required output levels and the extra cost to consumers. The energy requirement would be a function of the type of power plant, capture process and extent of capture.

Water requirements for the project are primarily for washing the treated flue gas exiting the absorber. Although the impact on existing water supply would be site specific, the required volumes are not expected to cause a significant adverse impact. For example, power plant feed-water flow rate for a 300 MW power plant is about 5,000 gpm, which is more than an order of magnitude greater than the estimated requirement for the project (see Section 2.5).

Solid and liquid wastes would be trucked offsite for disposal. On-site treatment of wastewater is not expected. Since the capture projects would be built close to existing industrial facilities, adequate road and/or rail infrastructure required for bringing in chemicals and other materials and for removing solid and liquid wastes are already expected to exist. Although traffic volume would increase, it is not expected to cause significant alterations in traffic patterns and rates, or cause conflicts with existing local and regional transportation plans.

4.12.3.2 CO_2 Compression and Transport

The compression and transport of CO_2 to a sequestration site requires the use of electricity and/or fuel to operate electric motors or engines that drive the compressors. Fuel is also required to operate the dehydrator. Other utility needs include cooling water for engines and wastewater and oil disposal.

Electricity required to compress CO_2 to injection pressures for a commercial-scale sequestration project would be obtained from the local power grid. Since the compressor station would be located in the vicinity of the capture site, existing electricity transmission infrastructure can be used to meet the power requirements.

If gas-fired engines would be used to drive the compressor motors and natural gas is not already available at the host facility, then access to a supply of natural gas would be required. The additional fuel use is not significant to adversely impact the supply and distribution of natural gas to the local markets. For example, a typical gas-fired CO_2 capture host facility boiler would consume about 3,000 MMBtu/hr which is about 20 times greater than the requirement for the CO_2 compressor facility (see Section 2.5).

Wastewater, which is mainly condensate from the compressed gas stream, and used lubricating oil are expected to be disposed of either in UIC Class II injection wells at the sequestration site or trucked for off-site disposal in approved wastewater treatment and disposal facilities.

Since the capture projects would be built close to existing industrial facilities, adequate road and/or rail infrastructure required for removing liquid wastes is already expected to exist. Increased traffic volumes would be minimal and would not be expected to cause significant alterations in traffic patterns and rates, or cause conflicts with existing local and regional transportation plans.

4.12.3.3 Sequestration in Geologic Formations

CO_2 sequestration projects require fuel and electricity during operation. Additionally liquid wastes (e.g., produced water and used lubricating oils) and solid wastes (e.g., well cuttings) that are generated during project construction and operation require proper disposal.

Fuel is required for injection well heating typically for coal seams and saline formation sequestration projects. If natural gas is already available at the site, it can be used as the fuel source. Alternatively, diesel-fired heaters can be used. In these cases diesel would be trucked to the site and stored in approved tanks or containers. Based on heating requirements, fuel usage rates are small and are not expected to disrupt local fuel supply and distribution.

Electricity demands at the sequestration sites are also minimal. Since these projects do not involve CO_2 compression (CO_2 is assumed to be compressed and delivered at injection pressures in the CO_2 transport project), electricity usage is limited to producing and handling produced fluids and re-injection. For example in EOR sequestration projects, electricity is required to operate pumps used to remove fluids from production wells, separate and treat the produced fluids, and inject produced water to enhance EOR. Electric-drive pumps can be used to dispose of fluids produced in sequestration projects by re-injection in underground injection wells. The electricity demand for these operations is small and can be supplied either by the CO_2 capture project's host facility (if the sequestration site is located close to a capture host facility) or by the local utility grid without significant impact to electricity transmission capacity margins. Electricity usage for basalt sequestration projects are expected to be similar to those of EOR sequestration projects. Based on availability, natural gas-fired internal combustion engines can also be used as prime movers for the pumps.

Wastewater produced at the site would be disposed of either in injection wells at the sequestration site or trucked off-site for disposal. The sequestration site is expected to have UIC Class II injection wells that allow such disposal. Solid wastes including well cuttings generated during the construction phase from injection and monitoring wells would be disposed of in a nearby landfill. The volumes generated are not expected to affect local landfill capacities significantly.

For sequestration in saline formations, there is a possibility of contamination of underground water reservoirs caused by subsurface leakage of the formation fluids. However, proper control of injection pressures coupled with continuous monitoring of the reservoirs, using MM&V technologies prior to, during, and for extended time periods following injection, can significantly reduce this risk.

4.12.3.4 Terrestrial Sequestration – Reforestation

Utility requirements for reforestation projects include fuel (e.g., diesel) required by heavy machinery that would be used to prepare and plant areas to be reforested. The fuel would be brought on site by road and stored in above ground tanks. The fuel requirements are not expected to adversely affect the supply and distribution of fuel in the area. Since the reforested areas may be remotely located, proper access roads would be required to bring in fuel and other materials (e.g., pesticides and fertilizers). Wastes including used lubricating oil and sanitary wastes would be collected and trucked off-site for disposal.

The fuel and waste removal rates are not expected to adversely affect local traffic patterns or volumes in the affected areas.

4.12.3.5 Co-Sequestration of CO_2 and H_2S in Depleted Oil and Gas Reservoirs, and Saline Formations

Utilities required for the co-sequestration of CO_2 and H_2S include steam, electricity, and water. Supplies of chemicals and other materials, as well as the disposal of solid and liquid wastes, are also required during operation.

During capture and separation of the acid gas stream from a commercial scale IGCC project, steam would be required which can be met by extracting steam at the required temperature and pressure from existing steam turbines at the facility (as is typical in cogeneration applications). The electricity power requirements would be small in comparison to the host facility's generation capacity. For acid gas streams obtained from sour gas processing facilities, incremental steam requirements would be negligible, and net electricity usage is expected to decrease when compared to typical sour gas processing requirements. Electricity requirements during compression, transport, and sequestration would be similar to those for pure CO_2 gas streams. Based on those electricity requirements, the co-sequestration of acid gas streams is not expected to require any significant changes to existing or future electric transmission infrastructure.

Incremental water requirements would be primarily for washing the treated flue gas exiting the absorber. Although the impact on existing water supply would be site-specific, the required volumes are not expected to cause a significant adverse impact. For example, the power plant feed-water flow rate for a 300 MW power plant is about 5,000 gpm (see Section 2.5), which is an order of magnitude greater than the estimated requirement for the model project.

For sequestration in saline formations, there is a possibility of contamination of underground water reservoirs caused by subsurface leakage of the formation fluids. However, proper control of injection pressures coupled with continuous monitoring of the reservoirs, using MM&V technologies prior to, during, and for extended time periods following injection, can significantly reduce this risk.

Significant rail and/or road infrastructure is required for delivery and handling of coal, chemicals, and other raw materials to an IGCC facility, as well as for the removal of by-products and wastes from the facility. These issues would be considered during project siting. However, the incremental infrastructure needs for the acid gas capture and separation operations would be minimal in comparison to the host facility. Therefore co-sequestration operations are not expected to require significant additional infrastructure over that required by the host facility.

Incremental solid and liquid wastes from the capture and separation operations would be trucked offsite for disposal. No on-site treatment of wastewater is expected. Wastes generated during transport and injection phases of the operation (e.g., condensed or produced wastewater, oils, etc.) would be trucked off-site or re-injected in approved UIC Class II injection wells that may be located at the sequestration site. Although traffic volumes would increase to meet incremental supply and disposal needs, it would not be expected to cause significant alterations in traffic patterns and volumes, or cause conflicts with existing local and regional transportation plans.

4.12.4 Mitigation of Potential Adverse Impacts

The following measures are recommended to mitigate potential adverse impacts of sequestration technologies on the utility infrastructure.

4.12.4.1 Project Planning and Design

- Identify utilities required and determine whether the available local utility infrastructure can adequately meet requirements.
- Identify alternatives if local infrastructure is inadequate. For example, if access to natural gas pipelines is unavailable, then the project design should include electric motors instead of gas-powered engines to drive compressors and pumps, or vice versa.
- Determine existing utility ROW for new CO_2 pipeline construction and identify potential barriers for alternative utility ROW.

4.12.4.2 Construction

- Identify whether adequate access roads are available to handle the volume and frequency of construction traffic to and from the proposed site.
- Discuss transportation plans with local authorities, especially during the movement of oversize loads, including construction equipment, drilling rigs, process equipment modules, and other heavy machinery.
- Develop a plan to reduce impacts of construction crews' traffic by proper scheduling and rotation of personnel.
- Create plans to handle and dispose of increased volumes of industrial and sanitation wastes generated during construction periods.

4.12.4.3 Operation

- Develop project-specific energy management plans to minimize materials and utilities usage.

- Identify opportunities for waste reduction to minimize wastewater and solid waste disposal volumes.

- Align schedules for delivery of materials (e.g., diesel fuel or chemicals) and for off-site waste disposal with host facility to minimize traffic to-and-from the project area.

4.12.5 Summary of Potential Impacts

Table 4-30 provides an overall qualitative assessment of potential impacts to the utility infrastructure for each sequestration technology.

The majority of impacts of all program technologies on the utility infrastructure would be negligible with a few impacts qualified as minor. In general, the primary needs of program technologies include energy sources (electricity or fuel), periodic supplies of raw materials, and periodic removals of wastes. Based on the relative energy demands and quantities of materials transported (supplies and wastes), the incremental impacts on the utility infrastructure would not be significant.

Impacts on water and wastewater infrastructure would be related to the size and distribution of potential facilities and/or region-specific issues affecting the ability to obtain a sustained supply of water or dispose of treated wastewater. Because volumes would be relatively small, the impacts are expected to be negligible or minor. Saline formation sequestration and co-sequestration of acid gas would have minor impacts on water resources based on the potential for contamination of underground water supplies caused by subsurface leakage of saline water. However, the use of MM&V technologies and proper control of injection pressures during operation would significantly reduce this risk.

Table 4-30. Potential Impacts of Program Technologies on Utility Infrastructure

Resource Criteria	Postcom Capture	Compr & Trans	Coal Seq	EOR Seq	Saline Seq	Basalt Seq	Terr Refor	Co-seq H_2S
Water supply and distribution	O	·	·	·	O	·	·	O
Wastewater treatment and disposal	O	O	O	O	·	O	·	O
Energy supply and distribution	·	·	·	·	·	·	·	·
Telecommunications	·	·	·	·	·	·	·	·
Roadways and traffic	·	·	·	·	·	·	·	·
Rail access	·	·	·	·	·	·	·	·

Key: · Negligible Impact, O Minor Adverse Impact, ⦿ Moderate Adverse Impact,
● Significant Adverse Impact, + Beneficial Impact

5.0 SUBJECT INDEX

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7.0 GLOSSARY AND ACRONYMS

ACRONYM OR TERM	DEFINITION
$\mu g/m^3$	microgram per cubic meter
$\mu g/mL$	microgram per milliliter
^{132}Xe	Xenon 132
1-hour average ozone concentrations	the EPA air quality standard for ozone is 0.12 part per million for a 1-hour average
^{20}Ne	Neon 20
^{36}Ar	Argon 36
^{84}Kr	Krypton 84
8-hour average ozone concentrations	the EPA air quality standard for ozone, designed to protect public health with an adequate margin of safety, is 0.085 parts per million (ppm), averaged over 8 hours
ac	acres
ACHP	Advisory Council on Historic Preservation
AEP	American Electric Power
afforestation	the conversion of bare or cultivated land into forest
AGR	acid gas removal
AHPA	Archeological and Historic Preservation Act
AIH	American Institute of Hydrology
AIRFA	American Indian Religious Freedom Act
ambient air	air of the surrounding environment; breathable air
ambient air pollutants	tropospheric gases that affect the absorptive characteristics of the atmosphere (CO, NO_2, SO_2 and O_3)
AMD	acid mine drainage
AMLIS	Abandoned Mine Land Inventory System
anthropogenic	caused or produced by humans
API Compendium	American Petroleum Institute
AQI	Air Quality Index
ARPA	Archeological and Historic Preservation Act
ASCC	Alaska Systems Coordinating Council
BACT	best available control technology
BEA	U.S. Bureau of Economic Analysis
BEG	Bureau of Economic Geology (University of Texas)
bgs	below ground surface
Big Sky Regional Partnership	consists of the states of Idaho, Montana, and South Dakota.
biomass	plant materials and animal wastes used especially as a source of fuel
BLM	Bureau of Land Management

BLS	Bureau of Labor Statistics
BMP	best management practice
bscfd	billion standard cubic feet per day
bsfc	brake specific fuel consumption
Btu/hp-hr	British thermal unit per horsepower-hour
Btu/scf	British thermal unit per standard cubic feet
c.f. or cu. ft.	cubic feet
CAA	Clean Air Act
CAAA	Clean Air Act Amendments (1990)
CAM	compliance assurance monitoring
CAN Europe	Climate Action Network Europe
Carbon Dioxide Capture	development and demonstration of technologies to efficiently separate CO_2 from emissions sources or the atmosphere and recovery of a concentrated stream of CO_2 that is amenable to sequestration or conversion
CAT	capillary absorption tubes
CBM	coal bed methane
CCP	CO_2 capture project
CCPI	Clean Coal Power Initiative
CCTP	Clean Coal Technology Program
CDM	Clean Development Mechanism
CEMs	continuous emissions monitors
CEQ	Council on Environmental Quality
CFC	chlorofluorocarbon
CFR	Code of Federal Regulations
CGA	Compressed Gas Association
CH_4	methane
CMI	Carbon Mitigation Initiative
CO	carbon monoxide
CO_2	carbon dioxide
CO_2 e	CO_2 equivalent
CO_2-ECBM	carbon dioxide-enhanced coal bed methane
CO_2-EOR	carbon dioxide-enhanced oil recovery
Coal-Seq	U.S Department of Energy research project designed to study various aspects of the sequestration process
Core R&D	includes laboratory studies and pilot plant operation, and small-scale field tests aimed at developing new technologies and new systems for GHG mitigation; these R&D efforts are focused in the areas of CO_2 capture, sequestration/storage, MMV, breakthrough concepts, and non-CO_2 GHG mitigation
CRBG	Columbia River Basalt Group

CRC	Canyon Reef Carriers
CREP	Conservation Reserve Enhancement Program
CRMP	Cultural Resource Management Plan
CSiTE	a research consortium, to perform fundamental research on terrestrial ecosystem carbon sequestration
CSLF	Carbon Sequestration Leadership Forum
CSO	Cognizant Secretarial Officers
CSSFA	Carbon Sequestration Science Focus Area
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
darcy	unit of permeability of a porous medium
DE	Distributed Energy program
DEA	diethanolamine
decayed organic materials	decomposition of animal and plant life
decennial	occurring every ten years
dissolved oxygen	amount of oxygen freely available in water necessary for aquatic life and the oxidation of organic materials
DOE	Department of Energy
DOI	Department of Interior
DOT	Department of Transportation
DPCC	Discharge Prevention Containment and Countermeasure/Discharge Cleanup and Removal Plan
dry domain	annual losses of water through evaporation at the earth's surface exceed annual water gains from precipitation
DSIRE	Database of State Incentives for Renewable Energy
EA	Environmental Assessment
ECAR	East Central Area Reliability Coordination Agreement
ECBM	enhanced coalbed methane
ecoregions	areas that share common climatic and vegetation characteristics
EEI	Edison Electric Institute
EERE	Energy Efficiency, & Renewable Energy office
EF	emission factor
EH	total hours worked by all employees during the calendar year
Eh	oxidation potential
EIA	Energy Information Administration
EIS	environmental impact statement
EMAN	Ecological Monitoring and Assessment Network
EMS	environmental management systems
endangered species	a species whose numbers are so small that the species is at risk of extinction

EO	Executive Order
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
EPRI	Electric Power Research Institute
EQIP	Environmental Quality Incentives Program
ERCOT	Electric Reliability Council of Texas, Inc
erosion	wearing away of land or soil by the action of wind, water, or ice
ES&H	environmental protection, safety, and health standards
ESA	Endangered Species Act
estuaries	water passage where the tide meets a river current
FAO	Food and Agricultural Organization
FDA	Food and Drug Administration
FEMA	Federal Emergency Management Agency
FEMP	Federal Energy Management Program
FIA	Forest Inventory and Analysis Program
FLEP	Forest Land Enhancement Program
forestation	any land-use change to forest use
fossil fuels	non-renewable source of energy (coal, oil and natural gas), which are burned to release the stored chemical energy
FRCC	Florida Reliability Coordinating Council
ft	feet
FutureGen	an initiative to build the world's first integrated sequestration and hydrogen production research power plant; the project is intended to create the world's first zero-emissions fossil fuel plant, employ the latest technology and serve as a large-scale engineering laboratory for testing new clean power, carbon dioxide capture, and coal-to-hydrogen technologies
FWS	Fish and Wildlife Service
FY	fiscal year
g/mile	grams/mile
gal/month	gallon per month
GCCI	Global Climate Change Initiative
GDP	gross domestic product
GEF	Global Environmental Facility
geologic hazards	a geologic condition or phenomenon that presents a risk or is a potential danger to life and property, either naturally occurring (e.g., earthquakes, volcanic eruptions) or man-made (e.g., ground subsidence)

geologic sequestration	various geologic formations utilized to sequester the captured CO_2, including depleted oil reservoirs, unmineable coal seams, saline formations, and other formations as determined on a site-specific basis
GHG	greenhouse gas
glaciation	expansion of continental glacial ice during a period of cold climate
gpd	gallon per day
gpm	gallons per minute
gpm	gallons per minute
greenhouse effect	a function of the concentration of water vapor, carbon dioxide, and other trace gases in the atmosphere that absorb terrestrial radiation leaving the surface of the earth
GRI	Gas Research Institute
groundwater	water in the zone of saturation below the water table
groundwater aquifers	porous subterranean regions saturated with groundwater
GSP	gross state product
GW	giga-watt
GWP	global warming potential (Measurement that describes its effect on climate change relative to a similar amount of CO_2)
H_2O	water vapor
H_2O/MMscf	water vapor per million standard cubic feet
H_2S	hydrogen sulfide
ha	hectare
HAPs	Hazardous Air Pollutants
hazardous waste	any waste or combination of wastes which pose a substantial present or potential hazard to human health, the environment, and plants or animals because such wastes are non-degradable or persistent in nature or because they can be biologically magnified, or because they can be lethal, or because they may otherwise cause or tend to cause detrimental cumulative effects
headwater streams	small narrow streams that collect much of the runoff and are the origin of most rivers
HFC	hydrofluorocarbon
hp	horsepower
hp / MMscf	horsepower per million standard cubic feet
hydrofracturing	process of expanding natural-occurring cracks in the rock with high pressure water
Hydrogen Fuel Initiative	an initiative that the President committed over five years to develop technology for commercially viable hydrogen-powered fuel cells
IC	internal combustion
IEA/GHG	International Energy Agency's Greenhouse Gas Research and Development Program
IECM-CS	Integrated Environmental Control Model-Carbon Sequestration

IGCC	integrated gasification combined cycle
igneous rocks	formed by the solidification and crystallization of a cooling magma (e.g., granite and basalt)
Illinois Basin Regional Partnership	consists of the states of Illinois, Indiana, and Kentucky
in	inch
inert	not readily reactive with other elements; forming few or no chemical compounds
INGAA	Interstate Natural Gas Association of America
INS	inelastic neutron scattering
in-situ	in place or 'on-site'
interglacial	warm period between two glacial periods
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
ISMS	Integrated Safety Management Systems
ITP	Industrial Technologies Program
JI	Joint Implementation
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
kWh/MMscf	kilowatt-hour per million standard cubic feet
lb/hr	pounds per hour
LFEE	Laboratory For Energy and the Environment
LIBS	Laser Induced Breakdown Spectroscopy
LPSO	Lead Program Secretarial Officers
LULUCF	land use, land use change, and forestry
m	meter
M3ADI	Multi-Spectral, 3-Dimensional Aerial Digital Imagery
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MDEA	3,4-methylenedioxy-N-ethylamphetamine
MEA	monoethanolamine
median	middle value in a set of measurements
metamorphic rocks	formed from other, pre-existing rocks that are subjected to very high temperatures and/or pressures (e.g., marble, quartzite, and slate)
mg/l	milligram per liter
mg/m^3	milligram per cubic meter
mi	mile
millidarcy (mD)	one-thousandth of a darcy

MIT	Massachusetts Institute of Technology
MIT	mechanical integrity test
mm	millimeter
MM&V	monitoring, mitigation, and verification
MMBtu/hr	million British thermal unit per hour
MMBtu/MMscf	million British thermal unit per million standard cubic feet
MMscfd	million standard cubic feet per day
MMT	million metric tons
MMTCE	million metric ton carbon equivalent
MOA	memoranda of agreement
MPa	million pascal
mpg	miles per gallon
MRCSP	Midwest Regional Carbon Sequestration Partnership
MRO	Midwest Reliability Organization
MSDS	the Material Safety Data Sheet explains the hazards that are posed by use of the material, personal protective equipment that should be worn when the material is used, and other precautionary measures
MSDS	see Material Safety Data Sheets
MSHA	Mine Safety and Health Administration
MT	metric ton
municipal solid waste	solid waste resulting from or incidental to residential, community, trade or business activities, including garbage, rubbish, ashes, and all other solid waste
MW	megawatt
N.A. or NA	not available
N_2-ECBM	nitrogen-enhanced coal bed methane
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAGPRA	Native American Graves Protection and Repatriation Act
NAICS	North American Industry Classification System
NAS	National Academies of Science
natural greenhouse effect	energy that is absorbed from terrestrial radiation and warms the Earth's surface and atmosphere
natural resources	the presence, distribution, quantity, and quality of geologic resources that are of economic value (e.g., oil, natural gas, coal, and others)
NCCTI	National Climate Change Technology Initiative
NEAP	Natural Events Action Plan
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NESHAPs	National Emission Standards for Hazardous Air Pollutants

NETL	National Energy Technology Laboratory
ng/mL	nanogram per milliliter
NGL	natural gas liquids
NGO	nongovernmental organization
NHPA	National Historic Preservation Act
NIOSH	National Institute of Occupational Safety and Health
NJDEP	New Jersey Department of Environmental Protection
NMFS	National Marine Fisheries Service
NNSA	National Nuclear Security Administration
NO	nitric oxide
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
nonattainment area	locality where air pollution levels persistently exceed National Ambient Air Quality Standards, or that contributes to ambient air quality in a nearby area that fails to meet standards
non-CO_2 GHG Mitigation	the pursuit of methods to reduce or avoid methane emissions by integrating abatement with energy production, conversion, and use; also, coordination with the U.S. Environmental Protection Agency (EPA) to assess the role that non-CO_2 emissions abatement can play in a nationwide strategy for reducing GHG emissions intensity
nonpoint source pollution	portion of precipitation on land that ultimately reaches streams often with dissolved or suspended material
non-renewable resources	resources that are not naturally regenerated or renewed
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRHP	National Register of Historic Places
NSPS	New Source Performance Standards
NSR	New Source Review
NWCC	National Wind Coordinating Committee
O_3	ozone
OAI	Office of Advanced Initiatives
OAQPS	Office of Air Quality Planning and Standards
^oC	degree Celsius
^oF	degree Fahrenheit
OGIP	original gas in place
OH	hydroxyl radical
OOIP	original oil in place
OPS	Office of Pipeline Safety
OSHA	Occupational Health And Safety Administration

OSRME	Office of Surface Mining Reclamation Enforcement
oxygen-depleting substances	any substance that causes a net loss of ozone in the stratosphere
PA	programmatic agreement
pathogen	organism capable of causing disease
Pb	lead
PC	pulverized coal
PCOR	Plains CO_2 Reduction Partnership. Consists of the states of Iowa, Missouri, Minnesota, North Dakota, Nebraska, Montana, South Dakota, Wisconsin, and Wyoming
pegmatites	coarse-grained veins formed when molten rock cools very slowly
permafrost	permanently frozen soil
PFCs	perfluorocarbons
pH	a measure of acidity and alkalinity of a solution (scale: 1-14; lower numbers indicate increasing acidity and higher numbers increasing alkalinity; which each unit of change represents a tenfold change)
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLF	Public Lands Foundation
PM	particulate matter
PM-10	particular matter particles up to 10 micrometers in diameter
PM-2.5	particular matter particles up to 2.5 micrometers in diameter
PNNL	Pacific Northwest National Laboratory
post-combustion capture	capture of CO_2 are mainly limited to the capture location (e.g., at the power plants, oil refineries, or industrial sites); effects would be site-specific, directly associated with the capture technology utilized, and dependent on the industrial CO_2 source
POTWs	Publicly Owned Treatment Works
ppb	parts per billion
PPII	Power Plant Improvement Initiative
ppm	parts per million
primary particles	particles such as dust from roads or black carbon (soot) from combustion sources, are emitted directly into the atmosphere
PSA	pressure swing absorption
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
QBtu	quadrillion British thermal units
R&D	research and development
RAMP	Rural Abandoned Mine Program
RCRA	Resource Conservation and Recovery Act
RD&D	research, development, and demonstration
reforestation	action of renewing forest cover by planting seeds or young trees

Regional Carbon Sequestration Partnerships	teams comprised of state agencies, universities, NGOs, and private companies with the goal of evaluating and pursuing opportunities for carbon sequestration deployment
reservoirs	a pond or lake where water is collected and stored until needed; or a porous and permeable sedimentary rock formation capable of storing gas or liquids.
RMOTC	Rocky Mountain Oilfield Testing Center
RMP	risk management plan
ROW	right-of-way
RPA	Resource Planning Act
RS	Revised Statute
runoff	rainfall not absorbed by soil
SACROC	Scurry Area Canyon Reef Operators Committee
saline formations	layers of porous rock that are saturated with brine water
SAMAB	Southern Appalachian Man and the Biosphere
SCADA	supervisory control and data acquisition
scf/day	standard cubic feet per day
SDWA	Safe Drinking Water Act
SECA	Solid State Energy Conversion Alliance
SECARB	Southeast Regional Carbon Sequestration Partnership
secondary containment	measure to prevent the release of stored liquids in the event of a failure of the primary containment tank
secondary particles	particles that are formed in the atmosphere from primary gaseous emissions
sedimentary rocks	formed when sediments are compacted or cemented together into a solid rock (e.g., sandstone, shale, and limestone)
sedimentation	solids naturally settling out of slow water in rivers, streams and other water bodies
separation membranes	allow CO_2 to pass through while excluding other parts
sequestration	development and demonstration of technologies for the placement of CO_2 into a repository such that it will remain stored for very long periods of time (hundreds to thousands of years); the three potential pathways for storage are geologic sequestration, terrestrial sequestration, and ocean sequestration
SERC	Southeastern Electric Reliability Council
SF_6	sulfur hexafluoride
SF_6	Sulfur hexafluoride
SHPO	State Historic Preservation Officer
siltation	see *sedimentation*
SIP	State Implementation Plan
SMCRA	Surface Mining Control and Reclamation Act
SO_2	sulfur dioxide

socioeconomics	study of the social and economic impacts of any product or service
solid waste	garbage, and other discarded solid materials resulting from industrial, commercial and agricultural operations, and from community activities
sorbents	materials that soak up liquids
Southeast Regional Partnership	consists of the states of Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia
Southwest Regional Partnership	consists of the states of Arizona, Colorado, Kansas, Nebraska, New Mexico, Oklahoma, Texas, Utah, and Wyoming
SO_x	sulfur oxides
SPCC	Spill Prevention Control and Countermeasures
SPDES	State Pollutant Discharge Elimination System
SPP	Southwest Power Pool, Inc.
stratosphere	region of the atmosphere above troposphere, and continues from 6 to 30 miles above the surface (10 km to about 50 km); most commercial airline traffic occurs in the lower part of the stratosphere
surface water	rivers, streams, lakes, ponds, reservoirs, wetlands, estuaries and coastal waters
SWPPP	Storm Water Pollution Prevention Plan
TBD	to be determined
TCAPP	Technology Cooperation Agreement Pilot Project
TCF	trillion cubic feet
TDS	total dissolved solids
TEG	triethylene glycol
TESS	Threatened and Endangered Species System
threatened species	species that is likely to become an endangered species within the foreseeable future throughout all or a significant part of its range
tonnes	metric ton
topography	physical features of surface land
total dissolved solids	accumulated total of all solids that might be dissolved in water
tpd	tons per day
tpy	tons per year
trace elements	a chemical element present in minute quantities
tracers	used to determine the fate and transport of the injected CO_2 stream
troposphere	lowest region of the atmosphere, and extends from the Earth's surface up to about 30 miles (10 kilometers) in altitude; virtually all human activities occur in the troposphere
TRS	total reduced sulfur
TSA	temperature swing absorption
TSCA	Toxic Substances Control Act
TSD	treatment, storage, and disposal

tundra	climate extends north of the Arctic Circle, from the Subarctic region to the Arctic Ocean; like the Subarctic region, the Tundra experiences extremely long periods of daylight in the summer and extended periods of darkness during winter months; annual precipitation is less than 14 inches, and much of the precipitation falls during the warm season in the form of rain or occasional wet snows
U.S.	United States
UIC	underground injection control
UMWA	United Mine Workers of America
UNFCC	United Nations Framework Convention on Climate Change
USACE	U.S. Appalachian Coalfield Region
USC	United States Code
USDA	U.S. Department of Agriculture
USDW	Underground Source of Drinking Water
USFWS	United States Fish and Wildlife Service
USGS	United States Geologic Survey
VOCs	volatile organic compounds
VRGGP	National Inventory and Voluntary Reporting of Greenhouse Gases Program
VRM	visual resource management
WECC	Western Electricity Coordinating Council
WESTCARB	West Coast Regional Carbon Sequestration Partnership. Consists of the states of Alaska, Arizona, California, Nevada, Oregon, and Washington
wetland	land areas which are seasonally or permanently saturated with water
xerophytic	pertaining to plants that are structurally adapted for life and growth with a limited water supply
yr	year

APPENDIX A. OTHER RELATED GHG PROGRAMS AND INITIATIVES

The Program is only one program aimed at reducing GHG emissions. There are a number of actions by international entities, presidential initiatives, DOE, other federal agencies, state jurisdictions, and NGOs that, in some way, complement the intent of the Program. The following list of GHG reduction programs is provided for information purposes *(and is not necessarily inclusive of all GHG programs and initiatives)*.

A.1 INTERNATIONAL TREATIES, PROGRAMS, AND POLICIES

The Rio Climate Treaty was signed in June 1992 in Rio de Janeiro, Brazil by more than 150 nations including the U.S. It has been ratified by many nations and seeks to stabilize the concentration of GHG concentrations; however, it does not set binding emissions limitations. Nations are urged to adopt their own national policies and measures.

More than 160 nations negotiated the Kyoto Protocol in December 1997, which became effective in February 2005. During the period 2008 to 2012, the protocol requires industrialized nations to reduce emissions of CO_2 and other specified heat-trapping gases to 5.2 percent below their 1990 levels. Through its Joint Implementation (JI) and the Clean Development Mechanism (CDM), industrialized countries would be able to achieve part of their emission reduction commitments by conducting emission-reducing projects abroad and counting the reductions achieved toward their own commitments. The U.S. has declined to ratify this legislation and will not participate in this agreement. A summary of International Treaties and other international programs and policies is included in Table A-1.

Table A-1. International Treaties, Programs, and Policies

Treaty/Program/Policy	Purpose	Website
Rio Climate Treaty	To stabilize the concentration of GHGs worldwide	www.climate.org/topics/intaction/index.shtml
Kyoto Protocol	To reduce GHG emissions worldwide	www.eia.doe.gov/oiaf/kyoto/execsum.html
Global Environmental Facility (GEF)	To transfer energy and sequestration technologies and other programs that protect the global environment to the developing world	www.gefweb.org/
United Nations Framework Convention on Climate Change (UNFCC)	To promote research on global climate change through mechanisms such as the Kyoto Protocol, which was an addition to the UNFCC	http://unfccc.int/2860.php
Carbon Sequestration Leadership Forum	To develop, improve, and make available technologies for separating and capturing CO_2 through international climate change initiatives	www.cslforum.org/

A.2 PRESIDENTIAL INITIATIVES

In addition to the National CCTI and the GCCI mentioned in Section 1.1, a number of other Presidential initiatives have been put into effect. The Clear Skies Initiative would set a national cap on sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) emissions through the introduction of a mandatory program in order to reduce power plant emissions. Also, in his State of the Union address on January 28, 2003, President Bush launched the Hydrogen Fuel Initiative. Through this initiative, the President committed $1.2 billion over five years to developing technology for commercially viable hydrogen-powered fuel cells. These fuel cells would not generate any pollution or GHG. The National Hydrogen Energy Roadmap outlines specific research objectives for this initiative. Additionally, the Debt for Nature Forest Conservation Programs (Tropical Forest Conservation Act) seeks to increase conservation funding for tropical forests that are valued for their carbon-storage capacity. A listing of Presidential initiatives is included in Table A-2.

Table A-2. Presidential Initiatives

Initiative	Purpose	Website
National Climate Change Technology Initiative (NCCTI)	To strengthen Federal leadership of climate change-related technology	www.climatescience.gov/about/nccti.htm
Global Climate Change Initiative (GCCI)	To reduce carbon intensity of the U.S. economy by 18 percent by 2012	www.whitehouse.gov/news/releases/2002/02/climatechange.html
Clear Skies Initiative	To set a National cap on power plant emissions of SO_2, NO_x, and Mercury	www.epa.gov/clearskies/
Hydrogen Fuel Initiative	To develop commercially-viable hydrogen-powered fuel cells	www.whitehouse.gov/news/releases/2003/02/20030206-2.html National Hydrogen Energy Roadmap
Debt for Nature Forest Conservation Programs (Tropical Forest Conservation Act)	To preserve tropical forests worldwide	www.usgcrp.gov

A.3 DOE ACTIONS

As outlined in the 2003 DOE Strategic Plan, a goal of the department is to "improve energy security by developing technologies that foster a diverse supply of reliable, affordable, and environmentally sound energy by providing for reliable delivery of energy, guarding against energy emergencies, exploring advanced technologies that make a fundamental improvement in our mix of energy options, and improving energy efficiency" (DOE, 2003). DOE has committed billions of dollars to initiatives and programs aimed at achieving near-zero GHG emissions. A summary of these initiatives is provided in Table A-3.

Table A-3. DOE Initiatives

Initiative	Purpose	Website
Biomass Research and Development Initiative	To provide $21 million in grants to carry out RD&D efforts on biomass energy, bio-based products, bio-fuels, and bio-power.	www.bioproducts-bioenergy.gov/default.asp
Clean Coal Power Initiative (CCPI)	To increase investment in clean coal technology through industry partnerships	www.netl.doe.gov/coal/ccpi
Climate Challenge Program Initiatives	To promote electric company-sponsored activities and projects aimed at the application of efficient electric technologies through 5 industry-wide initiatives	www.eei.org/industry_issues/environment/climate/pp_climate_challenge.pdf
Clean Energy Initiative	To improve the productivity and efficiency of current energy systems through the Efficient Energy for Sustainable Development Partnership	www.pi.energy.gov/clean_energy_initiative.html
Integrated Sequestration and Hydrogen Research Initiative (*FutureGen*)	To build the first integrated sequestration and hydrogen production power plant	www.fe.doe.gov/programs/powersystems/futuregen/index.html
North American Energy Working Group (NAEWG) – an energy initiative	To enhance cooperation between the U.S., Canada, and Mexico on energy-related matters	www.eia.doe.gov/emeu/northamerica/engindex.htm
Power Plant Improvement	To request proposals for and the potential funding of	www.netl.doe.gov/ppii/program/progr

Table A-3. DOE Initiatives

Initiative	Purpose	Website
Initiative (PPII)	commercial scale demonstrations of environmentally sound technologies, primarily coal-fired power plant technologies	am.html
Zero Energy Homes Research Initiative	To reduce the amount of energy consumed by single-family homes and to build more energy-efficiency homes	www.eere.energy.gov/buildings/tech/zeroenergy.html

A.3.1 DOE's Office of Fossil Energy, National Energy Technology Laboratory (NETL)

Within the Office of Fossil Energy, NETL's purpose is to develop advanced technologies related to coal, natural gas, and oil. NETL partners with industry, academia, and other governmental stakeholders to conduct and implement Research, Development, and Demonstration (RD&D) programs and to create commercially viable technical solutions to energy and environmental problems.

NETL oversees many high-profile projects and research efforts including the CCPI and the Integrated Sequestration and Hydrogen Research Initiative (FutureGen). The CCPI is President Bush's $2 billion, 10-year initiative to develop an environmentally sound generation of new coal-based electric power technologies for which industry will contribute matching funds of at least 50 percent. *FutureGen* is a $1 billion initiative to build the world's first zero-emissions, integrated sequestration and hydrogen production research power plant.

NETL's Strategic Center for Coal (SCC) focuses on creating opportunities for the sustainability of ultra-clean coal-to-energy plants through public and private sector partnerships and investments. The Program is one of the RD&D programs within the SCC at NETL. SCC projects include clean coal demonstrations, distributed energy projects, and carbon sequestration projects, including the successful Weyburn CO_2 Carbon Sequestration Project involving enhanced oil recovery. A list of these initiatives is included in Table A-4.

Table A-4. DOE Office of Fossil Energy and NETL Programs

Program	Purpose	Website
Clean Coal Technology Program (CCTP)	To develop improved environmentally-sound coal-based electric power To demonstrate and deploy advanced clean coal technologies	www.netl.doe.gov/cctc/programs/program.html www.fe.doe.gov/programs/powersystems/cleancoal/index.html
Office of Advanced Initiatives (OAI)	To provide overall management and implementation of non-fossil energy initiatives, including those with other Federal agencies	www.netl.doe.gov/oia/index.html
Strategic Center for Coal	To create and sustain clean coal technologies	www.netl.doe.gov/coal/main.html
Climate Change Policy Support	To develop and demonstrate fossil fuel-based technologies	www.netl.doe.gov/products/ccps/index.html
Vision 21	To develop fossil fuel power plants that will co-produce multiple commercial products	www.fe.doe.gov/programs/powersystems/vision21/index.html
Hydrogen & Other Clean Fuels	To investigate advanced hydrogen production technologies from fossil fuels, natural gas, and coal in order to develop commercially viable hydrogen-powered fuel cells to power cars, trucks, homes and businesses with no pollution or greenhouse gases.	www.fe.doe.gov/programs/fuels/index.html

Table A-4. DOE Office of Fossil Energy and NETL Programs

Program	Purpose	Website
Oil & Gas Supply & Delivery	To investigate ways to enhance oil production (e.g. using carbon dioxide to force more oil to the surface while trapping this greenhouse gas underground).	www.fe.doe.gov/programs/oilgas/eor/index.html

A.3.2 DOE's Energy Efficiency & Renewable Energy Office (EERE) Programs

The DOE's Energy Efficiency & Renewable Energy Office (EERE) oversees 11 programs geared toward increasing the use of renewable-energy technologies, increasing energy efficiency, and reducing the energy intensity of industry. Each of these programs is currently involved in R&D of new technologies and the continuation of existing innovative efforts.

Many of these programs are collaborations between EERE and other offices, agencies, or private industries. For example, DOE's Hydrogen Fuel Cells and Infrastructure Technologies Program integrates the efforts of 4 offices to research, develop, and validate fuel cell technologies and hydrogen production, delivery, and storage technologies. The Weatherization and Intergovernmental Program works with communities, manufacturers, consumers, and businesses and has partnered with various state and local energy organizations to support and provide funding for projects which promote energy efficiency in buildings, use of renewable energy on tribal lands, and commercialization of innovative energy-efficient technologies.

The EERE's wide array of programs includes:

- Building Energy Codes
- Clean Cities
- ENERGY STAR®
- International Renewable Energy Program
- Inventions & Innovation
- NICE3
- Rebuild America
- State Energy Program
- Tribal Energy Program
- Weatherization Assistance Program

These and other key programs are referenced in Table A-5.

Table A-5. DOE Energy Efficiency, & Renewable Energy Office (EERE) Programs

Program	Purpose	Website
Biomass Program	To develop technology for conversion of biomass (plant-derived material) to valuable fuels, chemicals, materials and power	www.eere.energy.gov/biomass/
Building Technologies Program (include Building America)	To improve energy efficiency of buildings through innovative technologies and better building practices	www.eere.energy.gov/buildings/
Distributed Energy (DE) Program	To support cost-effective R&D programs aimed at improving opportunities for promoting distributed energy equipment	www.eere.energy.gov/de/

Table A-5. DOE Energy Efficiency, & Renewable Energy Office (EERE) Programs

Program	Purpose	Website
Federal Energy Management Program (FEMP)	To reduce the costs and environmental impact of the Federal government through the promotion of water conservation and energy efficiency	www.eere.energy.gov/femp/
FreedomCAR and Vehicle Technologies Program	To develop advanced transportation technologies to reduce the nation's use of imported oil and improve air quality	www.eere.energy.gov/vehiclesandfuels/
Geothermal Technologies Program	To promote geothermal energy as an economically competitive contributor to the U.S. energy supply	www.eere.energy.gov/geothermal/
Hydrogen, Fuel Cells & Infrastructure Technologies Program	To accelerate the development and market introduction of hydrogen and fuel cell technologies	www.eere.energy.gov/hydrogenandfuelcells/
Industrial Technologies Program (ITP)	To improve the energy efficiency and environmental performance of U.S. industries	www.eere.energy.gov/industry/
Solar Energy Technologies Program	To develop solar energy technologies as a viable energy source	www.eere.energy.gov/solar/
Weatherization and Intergovernmental Program	To facilitate the adoption of energy-efficient technologies and policies	www.eere.energy.gov/wip/about/about.html
Wind and Hydropower Technologies Program	To promote wind power so that it can competitively compete with other sources of energy	www.eere.energy.gov/windandhydro/

A.3.3 DOE's Office of Science

In support of carbon-sequestration initiatives, DOE's Office of Science focuses its efforts on various endeavors including:

- Sequestering carbon in underground geologic repositories;
- Enhancing the natural terrestrial cycle;
- Carbon sequestration in the oceans; and
- Sequencing genomes of micro-organism for carbon management.

Also, one of the Office of Science research branches, the Office of Biological and Environmental Research, has established a research consortium, CSite, to perform fundamental research on terrestrial ecosystem carbon sequestration.

A.3.4 DOE Interagency/Industry Efforts

Through partnerships with private industry and governmental agencies such as EPA, the Department of Transportation (DOT), USDA, and the Department of Interior (DOI), DOE has initiated many efforts to reduce GHG emissions. Some of the key DOE interagency/industry efforts are outlined in Table A-6.

Table A-6. Key DOE Interagency/Industry Efforts

Efforts	Purpose	Website
U.S. Climate Change Technology Program (CCTP)	To review the portfolio of more than $2 billion in climate change research activities and make periodic recommendations.	www.climatetechnology.gov/ www.climatetechnology.gov/library/2003/currentactivities/index.htm
Climate VISION Partnership	To reduce greenhouse gas intensity through partnerships with U.S. EPA, DOT, USDA, and DOI.	www.climatevision.gov/
Climate Challenge Program	To cut greenhouse gas emissions through a voluntary program initiated by the electric utility industry and DOE.	www.we-energies.com/environment/gcc_climate_challenge.htm

A.3.5 Other DOE Efforts

Other DOE efforts for the reduction of GHG emissions include the Technology Cooperation Agreement Pilot Project (TCAPP), the National Inventory and Voluntary Reporting of Greenhouse Gases Program (VRGGP), the GHG Reduction and Sequestration Registry, and additional activities outlined in Table A-7.

Table A-7. Other DOE Efforts

Efforts	Purpose	Website
Database of State Incentives for Renewable Energy (DSIRE)	To provide a comprehensive source of information on state, local, utility, and selected federal incentives that promote renewable energy	www.dsireusa.org/
Technology Cooperation Agreement Pilot Project (TCAPP)	To promote and encourage climate change technology cooperation with developing countries and to facilitate voluntary partnerships between several governments and the private sector.	www.bcse.org/tcapp.html
National Inventory and Voluntary Reporting of Greenhouse Gases Program (VRGGP)	To promote voluntary actions, under DOE's 1605(b) program, to reduce emissions and meet U.S. commitments under the Framework Convention on Climate Change	www.eia.doe.gov/oiaf/1605/frntvrgg.html
GHG Reduction and Sequestration Registry	To recognize greenhouse gas reductions by non-governmental organizations, businesses, farmers, and the federal, state and local governments.	www.usgcrp.gov/usgcrp/Library/gcinitiative2002/gccstorybook.doc

A.4 OTHER FEDERAL AGENCIES

In addition to the efforts currently underway at DOE, other federal agencies, such as EPA, USDA, DOT, DOI, and the National Oceanic and Atmospheric Administration (NOAA), are involved in projects concerned with GHG emissions reduction and energy efficiency. The contributions of these programs towards reducing GHG emissions are provided in more detail in Appendix D “Cumulative Impacts”.

A.4.1 U.S. Environmental Protection Agency (EPA)

Through environmental research and sponsorship of voluntary programs and partnerships, EPA has taken a lead role in energy-conservation efforts and minimization of GHGs. In turn, the agency provides the partners and the public with access to emerging technology information. Table A-8 outlines some of EPA's key energy related program areas and partnerships, including the Coalbed Methane Outreach Program (CMOP), the Green Power Partnership, the Climate Leaders Program, and the Methane to Markets Partnership.

Table A-8. Key EPA Program Areas

Key Programs	Purpose	Website
Climate Leaders Program	To encourage companies to develop long-term comprehensive climate change strategies and set greenhouse gas (GHG) emissions reduction goals	www.epa.gov/climateleaders/
Methane to Markets	To promote cost-effective, near-term methane recovery and use as a clean energy source.	http://www.epa.gov/methanetomarkets/
Energy Star	To provide energy efficient products for home and business and provide energy efficient management options through business partnerships	www.energystar.gov/
Networked Environmental Information System for Global Emissions Inventories (NEISGEI)	To create a web-based global air emissions inventory network to provide emissions data and inventories	www.neisgei.org/
Green Power Partnership	To encourage organizations to use green power as part of a best management practices environmental program.	www.epa.gov/greenpower/index.htm
Coalbed Methane Outreach Program	To reduce methane emissions from coal mining activities through identification of obstacles to investments in methane recovery technology, and identification and implementation of ways to use coal mine methane	www.epa.gov/cmop/
SF_6 Emission Reduction Partnership for Electric Power Systems	To identify and implement cost-effective solutions to reduce sulfur hexafluoride (SF_6) emissions through a voluntary partnership with over 70 utilities	www.epa.gov/highgwp/electricpower-sf6/index.html
Environmental Technology Verification Program (ETV)	To test and verify the validity of innovative energy technologies which improve energy efficiency, reduce greenhouse gas emissions, and improve performance of fossil fuels through the ETV Greenhouse Gas Technology Center	www.epa.gov/etv/

A.4.2 U.S. Department of Agriculture (USDA)

USDA provides incentives - through financial grants, technical assistance, and pilot programs - to private landowners, including farmers and forest and grazing landowners, for implementing practices that reduce GHG and store carbon. "In FY2004, USDA will invest almost $3.9 billion in agriculture and forest conservation, an increase of $1.7 billion over FY 2001 levels" (USDA, 2003). Among the major programs are the Environmental Quality Incentives Program (EQIP), the Forest Land Enhancement Program (FLEP), Conservation Reserve Enhancement Program (CREP), Greenhouse Gas Pilot Projects, and the Greenhouse Gas Accounting Protocols. Additionally, through partnerships with private industry such as the American Forest and Paper Association and the National Rural Electric Cooperative Association, USDA works to improve GHG intensity and promote renewable energy. Table A-9 lists some of USDA's program areas.

Table A-9. Key USDA Program Areas

Key Programs	Purpose	Website
Global Change Program	To investigate the current and potential role of agriculture in the global carbon cycle through its Carbon Cycle and Carbon Storage Research Program	www.ars.usda.gov/research/programs/programs.htm?NP_CODE=204
Forest Land Enhancement Program (FLEP)	To promote carbon sequestration through activities such as afforestation, reforestation, forest stand improvements, agro-forestry, and windbreaks	www.fs.fed.us/spf/coop/programs/loa/flep.shtml
Conservation Reserve Enhancement Program (CREP)	To provide agricultural landowners with incentives in the form of annual rental payments and cost-share assistance for installing specific conservation practices on eligible land	www.fsa.usda.gov/dafp/cepd/crep.htm
The Environmental Quality Incentives Program (EQIP)	To provide financial and technical assistance to farmers and ranchers to install or implement conservation practices on eligible agricultural land	www.nrcs.usda.gov/programs/eqip/
Greenhouse Gas Pilot Projects	To encourage farmers and other private landowners to adopt land management practices that will store carbon and reduce greenhouse gases	http://japan.usembassy.gov/e/p/tp-20030609b8.html
Greenhouse Gas Accounting Protocols	To develop new accounting rules and guidelines for reporting greenhouse gas emissions in order to improve the voluntary greenhouse gas registry	http://japan.usembassy.gov/e/p/tp-20030609b8.html
The Wetland Reserve Program (WRP)	To protect, restore, and enhance wetlands through technical and financial support to eligible landowners	www.nrcs.usda.gov/programs/wrp/
USDA Partnerships	To improve greenhouse gas intensity and eliminate barriers to farmers/ranchers in generating renewable energy	www.nreca.org/nreca/Press_Room/Press_Releases/Current/20031022PressRelease.html

A.4.3 U.S. Department of Transportation (DOT)

The DOT's Center for Climate Change and Environmental Forecasting (http://climate.volpe.dot.gov/about.html) uses research and analysis, outreach activities and partnerships, strategic planning, and policy assessment to reduce transportation-related GHGs.

A.4.4 U.S. Department of Interior (DOI)

In September 2004, the DOI Bureau of Land Management (BLM) released a Draft Programmatic Environmental Impact Statement (DPEIS) on wind-energy development. The report evaluates environmental, social, and economic impacts associated with wind energy development on Western public lands (excluding Alaska) administered by the BLM. A full text version and summary of the PEIS can be found at http://windeis.anl.gov/.

Furthermore, the DOI Office of Surface Mining's (OSM) Abandoned Mine Lands (AML) program provides for the restoration of eligible lands and waters mined and abandoned or left inadequately restored. By reforesting abandoned mine lands, the program supports the goals of terrestrial carbon sequestration.

A.4.5 National Oceanic and Atmospheric Administration (NOAA)

NOAA has a number of programs focused on investigating the ocean carbon cycle. The key programs include the Atlantic Oceanographic and Meteorological Laboratory (AOML) Carbon Dioxide Program, the Pacific Marine Environmental Laboratory (PMEL) Carbon Dioxide Program, and the Global Carbon Cycle Program outlined in Table A-10.

Table A-10. Key NOAA Program Areas

Key Programs	Purpose	Website
Atlantic Oceanographic and Meteorological Laboratory (AOML) Carbon Dioxide Program	To assess the ocean's role in controlling atmospheric CO_2 levels with focus on observations of the exchange of CO_2 across the air-sea interface and its eventual penetration into the water masses of the deep ocean	www.aoml.noaa.gov/ocd/gcc/co2research/
Pacific Marine Environmental Laboratory (PMEL) Carbon Dioxide Program	To conduct ocean carbon cycle research from ships and moorings in all of the major ocean basins in collaboration with AOML's Carbon Dioxide Program	www.pmel.noaa.gov/co2/co2-home.html
Global Carbon Cycle Program	To improve the ability to predict the fate of anthropogenic CO_2 and future atmospheric CO_2 concentrations using a combination of atmospheric and oceanic global observations, process-oriented field studies and modeling	www.ogp.noaa.gov/mpe/gcc/

A.4.6 Other Federal Agencies

The Carbon Cycle Science Program is an interagency partnership focused on research relating to the understanding of the global carbon cycle. It includes the U.S. Global Change Research Program (USGCRP) and the North American Carbon Program (NACP). A major research effort of the program is to identify, characterize, quantify, and project the major regional sources and sinks of CO_2. This program coordinates the research of 10 federal departments and agencies. It included a budget of $221 million in FY 2002 for research projects. More information on this program can be found at http://www.carboncyclescience.gov/.

A.5 REGIONAL ENTITIES

There are a number of states and regions in the U.S. that have CO_2 emissions reduction regulatory requirements and/or statewide emissions reduction target commitments established by Executive Order, as outlined in Tables A-11 and A-12. Figure A-1 summarizes the status of state progress on GHG inventories and action plans. Additional information on state and regional GHG reduction programs is also found in Appendix D "Cumulative Impacts". Information on the Regional Greenhouse Gas Initiative is found in Section A.5.1.

Table A-11. Regional Projects/Programs

Project/Program	Purpose	Website
Clean Air – Cool Planet (NE partnership)	To create partnerships and local initiatives aimed at reducing greenhouse gases	www.cleanair-coolplanet.org/
Climate Solutions	To helping the Pacific Northwest become a world leader in global warming solutions through programs such as the Northwest Clean Energy Challenge that recognizes businesses, governments, and utilities that invest in renewable energy	www.climatesolutions.org/

Table A-11. Regional Projects/Programs

Project/Program	Purpose	Website
Mid-Atlantic Renewable Energy Coalition	To increase consumer demand for clean electricity in the Mid-Atlantic states	www.cleanyourair.org/
Renewable Northwest Project (RNP)	To promote renewable energy projects in the Northwest by encouraging businesses and governments to participate	www.rnp.org/
Western Resource Advocates	To promote sustainable energy technologies in the Rocky Mountain and Desert Southwest areas through projects such as the Western Resource Advocates' Energy Project	www.westernresourceadvocates.org
Southern Alliance for Clean Energy	To monitor and propose energy policies which are beneficial both environmentally and economically to the area	www.cleanenergy.org/
Regional Greenhouse Gas Initiative	A cooperative effort by Northeastern and Mid-Atlantic states to reduce CO_2 emissions.	www.rggi.org

Table A-12. State Legislative and Policy Initiatives Pertaining to GHG

Voluntary		*Mandatory*					*Market-based*	
GHG Reduct. Targets	*GHG Registry*	*Sector Target Caps*	*Sector Min. Stds*	*GHG Emiss. Discl.*	*Carbon Seq.*	*Other Emiss. Reduct.*	*Trading Prog.*	*Offsets Prog*
CT	CA	IL (P)	CA	CT	HI	HI	CT (P)	MA
MA	CT (P)	MA	MA	MA	FL	MD	MA (P)	NH
MD (P)	IL (P)	NH	OR	MD	MN	TN	MD (P)	OR
ME	MA (P)	WA (P)		NC	NE	VT	ME (P)	
NH	MD (P)	WI (P)		NV	ND		NH (P)	
NJ	ME (P)				OK		NJ*	
NY (P)	NH				OR		RI (P)	
RI	NJ				RI (P)		VT (P)	
VT	NY (P)				WY			
	RI (P)							
	TX (P)							
	VT (P)							
	WI							

*NJ trading plan abandoned in September, 2002.

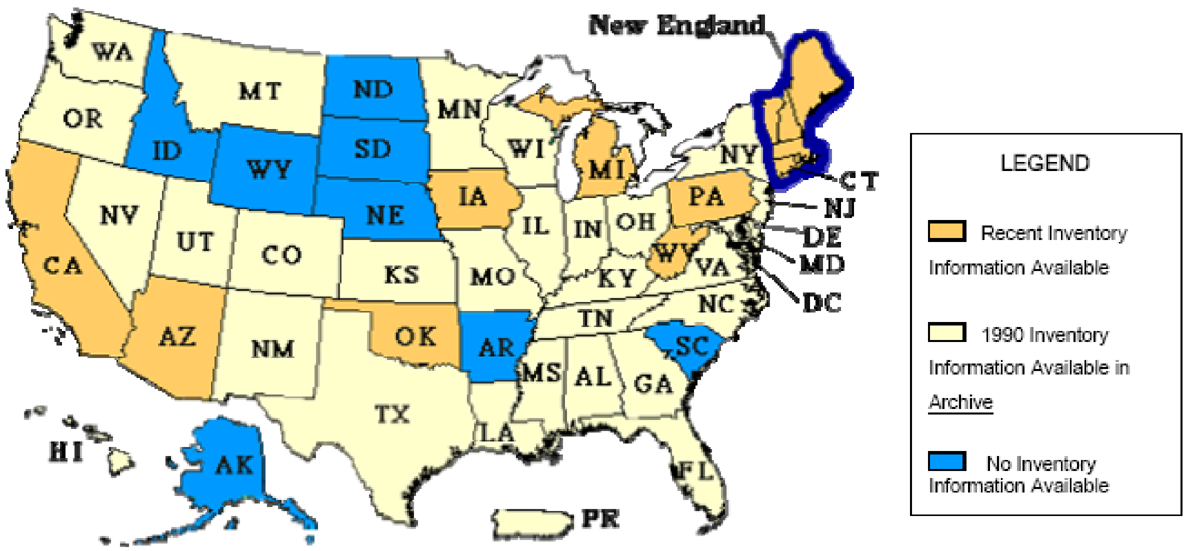

Figure A-1. Status of State GHG Inventories and Action Plans

A.5.1 Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by 9 Northeast and Mid-Atlantic states to discuss the design of a regional cap-and-trade program initially covering CO_2 emissions from power plants in the region. This program would regulate emissions from fossil fuel-fired electricity generating units having a rated capacity equal to or greater than 25 megawatts. In the future, RGGI may be extended to include other sources of greenhouse gas emissions, and greenhouse gases other than CO_2 (RGGI, 2006)

On December 20, 2005, seven states announced an agreement to implement the Regional Greenhouse Gas Initiative, as outlined in a Memorandum of Understanding (MOU) signed by the Governors of the participating states. The states that agreed to sign the MOU are Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. The MOU outlines the program in detail, including the framework for a Model Rule to be developed in 2006. The Model Rule will be released in draft form, affording stakeholders and the public an opportunity to submit comments. The states anticipate the release of a draft Model Rule 90 days after signing of the MOU (RGGI, 2006).

The first compliance period will commence January 1, 2009, where through 2014, each state's base annual CO_2 emissions budget shall remain unchanged. Beginning in 2015, each state's base emissions budget will decline by 2.5 percent per year, so that each state's budget for 2018 will be 10 percent below its initial annual budget. If this goal were achieved, total regional CO_2 emissions reductions would be approximately 12 million short tons (11 million metric tons [MMT]) per year from baseline levels. Under the MOU, the signatory states would commence a comprehensive review of the program in 2012, the same timeframe as the federal GCCI review.

The program emphasizes energy efficiency and non-carbon emitting energy generation technologies to meet the CO_2 emissions reduction goal. In each compliance period, a source may cover up to 3.3 percent of its reported emissions with offset allowances.

Initially, offsets allowances may be issued to verified reduction projects anywhere in the U.S. in the following areas:

- Natural gas, heating oil, and propane energy efficiency;
- Landfill gas capture and combustion;
- Methane capture from animal operations;
- Forestation of non-forested land;
- Reductions of sulfur hexafluoride (SF6) emissions from electricity transmission and distribution equipment; and
- Reductions in fugitive emissions from natural gas transmission and distribution systems.

The MOU allows offsets from states outside the signatory states, but with only half credit provided for outside projects. However, if the price of CO_2 allowances exceeds a certain level, use and geographic location of offset allowances would be expanded.

The MOU also states that if a federal program is adopted that is comparable to the RGGI, the signatory states would transition to the federal program.

A.6 NON-GOVERNMENTAL ORGANIZATIONS

In addition to their various partnerships with government agencies, non-government organizations (NGOs) have formed their own collaborations to promote the reduction of GHG emissions, develop markets for green power, and participate in the brokering and trading of GHG emission allowances and offsets. A total of 267 NGOs attended the ninth session of the Conference of the Parties in Milan, Italy in December 2003. Some of the key GHG-related NGOs are listed in Table A-13.

Table A-13. Non-Government Organizations (NGO's)

Organization	Purpose	Website
Business Council for Sustainable Energy	To promote market-based approaches for reducing pollution and providing a diverse, secure mix of energy resources	www.bcse.org/
Center for Energy and Climate Solutions	To promote clean and efficient energy technologies as a money-saving tool for reducing greenhouse gas emissions and other pollutants	www.energyandclimate.org/
Center for Environmental Leadership in Business	To engage the private sector worldwide in promoting policy solutions and test ideas aimed at creating solutions to critical global environmental problems	www.celb.org/xp/CELB/
Chicago Climate Exchange (CCX)	To establish a rules-based market for reducing and trading greenhouse gas emissions	www.chicagoclimatex.com/
Clean Air Canada, Inc. (CACI; becoming EMA-Canada)	To develop and facilitate market-based approaches to reducing, offsetting, and managing emissions through the review and register of emission reduction activities at various organizations, providing a forum for information exchange, and promoting public education and communication	www.cleanaircanada.org/
Climate, Community & Biodiversity Alliance	To combine technical, business, and policy expertise to promote land-use-based carbon offsets as equitable, measurable, and cost effective solutions for managing multiple global problems	www.celb.org/xp/CELB/programs/climate/ccba.xml

Table A-13. Non-Government Organizations (NGO's)

Climate Neutral Network	To develop products and enterprises that eliminate their impacts on the earth's climate	www.climateneutral.com/
Clinton Climate Initiative (CCI)	To make a difference in the fight against climate change in practical and measurable ways, initiating programs that directly result in substantial reductions in heat-trapping greenhouse gas emissions.	http://www.clintonfoundation.org/cf-pgm-cci-home.htm
Emissions Marketing Association (EMA)	To promote market-based trading solutions for environmental management	www.emissions.org/
Environmental Defense (ED) – Partnership for Climate Action (PCA)	To promote investments to reduce emissions and work on effective strategies to cut industrial pollutants such as carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and other GHGs through partnerships with member companies	www.environmentaldefense.org/system/templates/page/subissue.cfm?subissue=3
Environmental Resources Trust (ERT) -- The Greenhouse Gas Registry Program	To report and track greenhouse gas emissions through voluntary reporting and establish an emissions trading market	www.ert.net/ghg/index.html
Global Environmental Management Initiative (GEMI)	To investigate business opportunities and risks related to the growing concern about global climate change	www.gemi.org/
Global Reporting Initiative (GRI)	To develop and disseminate globally applicable Sustainability Reporting Guidelines which report on the economic, environmental, and social dimensions of their activities, products, and services	www.globalreporting.org/
Greenhouse Emissions Management Consortium (GEMCO)	A not-for-profit Canadian corporation formed by companies that wish to demonstrate industry leadership in developing voluntary and market-based approaches to greenhouse gas emissions management.	www.gemco.org/
Intergovernmental Panel on Climate Change (IPCC)	To assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation.	http://www.ipcc.ch/index.html
International Emissions Trading Association (IETA)	To develop an active, global greenhouse gas market and ensure effective business participation	www.ieta.org/ieta/www/pages/index.php
Joint Program on the Science and Policy of Global Climate Change	To conduct research, independent policy analysis, and public communication on issues of global environmental change	http://web.mit.edu/globalchange/www/
Pew Center – Business Environmental Leadership Council (BELC)	To respond to the challenges posed by climate change by working with various companies who address climate change by establishing and meeting emissions reduction objectives; investing in new, more efficient products, practices, and technologies; and supporting actions to achieve cost-effective emissions reductions	www.pewclimate.org/companies_leading_the_way_belc/
The Climate Crisis Coalition	To broaden the circle of individuals, organizations and constituencies engaged in the global warming issue, to link it with other issues and to provide a structure to forge a common agenda and advance action plans with a united front.	http://www.climatecrisiscoalition.org/
The Climate Group	To advance business and government leadership on climate change.	http://www.theclimategroup.org/index.php?pid=354
The Climate Trust	To promote climate change solutions by providing high quality greenhouse gas offset projects and advancing sound offset policy	www.climatetrust.org/

Table A-13. Non-Government Organizations (NGO's)

United Nations Framework Convention on Climate Change (UNFCCC)	An international treaty to begin to consider what can be done to reduce global warming and to cope with whatever temperature increases are inevitable. A number of nations have approved an addition to the treaty: the Kyoto Protocol, which has more powerful (and legally binding) measures. The UNFCCC secretariat supports all institutions involved in the climate change process, particularly the COP, the subsidiary bodies and their Bureau.	http://unfccc.int/2860.php
Voluntary Challenge & Registry (VCR)	To promote voluntary approaches to addressing climate change through a non-profit partnership between Industry and governments across Canada	www.vcr-mvr.ca/
World Bank – Global Gas Flaring Reduction Partnership (GGFRP)	To support national governments and the petroleum industry in their efforts to reduce flaring and venting of gas associated with the extraction of crude oil	http://www2.ifc.org/ogmc/global_gas.htm
World Bank – Prototype Carbon Fund (PCF)	To aid borrowing client countries in combating climate change, promote sustainable development, and demonstrate the possibilities of public/private partnerships	http://carbonfinance.org/pcf/router.cfm?Page=About#4
World Business Council for Sustainable Development (WBCSD)	To promote sustainable development via the three pillars of economic growth, ecological balance, and social progress through a coalition of 170 international companies	http://www.wbcsd.ch/templates/TemplateWBCSD5/layout.asp?MenuID=1
World Economics Forum	To engage leading businesses and environmental organizations to participate in a Global Greenhouse Gas (GHG) Register to promote corporate GHG emission transparency.	www.weforum.org/site/homepublic.nsf/Content/Global+Greenhouse+Gas+Register
World Resources Institute (WRI)	To protect the global climate system from further harm due to emissions of greenhouse gases	www.wri.org/
World Wildlife Fund (WWF) – Climate Savers	To engage environmentally committed businesses to develop and adopt innovative climate and energy solutions	www.worldwildlife.org/climate/projects/climate_savers.cfm

A.7 MISCELLANEOUS RESEARCH

Various laboratories and institutes are conducting research that addresses energy conservation, reduction of GHGs, the introduction of new technologies, and understanding of the carbon cycle and its effect on the environment. In the U.S., key research efforts are underway at Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, Princeton University, and other institutions as outlined in Table A-14.

Table A-14. Miscellaneous Research (U.S.)

Research	Purpose	Website
The Ocean Biogeochemical Processes Group (OBPG) at E.O. Lawrence Berkeley National Laboratory	To investigate the ocean's carbon cycle (such as how it will change in response to increased CO_2 in the atmosphere, and how to feasibly, effectively, and economic use the oceans to sequester CO_2) through various research projects	http://www-ocean.lbl.gov/
Climate and Carbon Modeling Group at Lawrence Livermore National Laboratory	To perform simulation models of the key processes that affect the atmosphere, oceans, and biosphere in an effort to understand the mechanisms of global environmental and climate change	http://eed.llnl.gov/cccm/

Table A-14. Miscellaneous Research (U.S.)

Research	Purpose	Website
The Greenhouse Gas Registry Program	To report and track GHG emissions through voluntary reporting and establish an emissions trading market	www.ert.net/ghg/index.html
Carbon Management and Sequestration Program	To research technologies which have the potential to capture, utilize, and store CO_2 from stationary sources	http://lfee.mit.edu/programs/cms
Ocean Chemistry of Greenhouse Gases	To further work in the area of ocean chemistry and GHGs including experiments on deep-sea release of liquid CO_2	www.mbari.org/ghgases/

APPENDIX B. CARBON SEQUESTRATION PROJECTS, INITIATIVES AND TECHNOLOGIES

This appendix provides details about existing and ongoing carbon sequestration research projects, initiatives and technologies. Although some of the projects and initiatives described here are being sponsored by DOE, the majority are sponsored by other government agencies, the private sector, or foreign governments. These descriptions are provided for both:

- technologies that are in the very earliest stages of research, where deployment at the demonstration or commercial scale would not occur before 2012, and
- existing and ongoing projects in the U.S and other countries, where the descriptions help exemplify the types and scales of research being conducted around the world.

Technologies and related projects described in this appendix include:

- Pre-Combustion Decarbonization
- Post-Combustion Capture
- Oxygen-Fired Combustion
- Advanced Conversion
- Sequestration in Coalbeds
- Enhanced Oil Recovery and Enhanced Gas Recovery
- Sequestration in Saline Formations
- Sequestration in Other Novel Formations
- Terrestrial Sequestration
- Ocean Fertilization
- Deep Ocean Injection of CO_2
- Geologic Sequestration MM&V
- Terrestrial Sequestration MM&V
- Breakthrough Concepts
- Non-CO_2 Greenhouse Gas Mitigation

B.1 PRE-COMBUSTION DECARBONIZATION

Pre-combustion decarbonization involves the removal of carbon from a gaseous, liquid, or solid fuel before it is burned through various approaches. A very promising technology involves gasifying coal and then scrubbing the CO_2 from the fuel gas before combustion. The CO_2 is normally removed by a chemical or physical absorption system. Existing capture technologies operate at a low temperature, requiring the synthesis gas (syngas) produced in the gasifier to be cooled for CO_2 capture and then reheated before combustion in a turbine (Klara and Srivastava, 2002). There are 10 oxygen-fired gasifiers in operation in the U.S. today. Syngas from an oxygen-fired gasifier can be shifted to provide a stream primarily of hydrogen (H_2) and CO_2 at 400-800 pounds per square inch (psi). Glycol solvents can capture CO_2 and be regenerated via flash (no steam use) to produce pure CO_2 at 15-25 psi (NETL, 2005b). Substantial cost reductions in CO_2 capture and separation are expected to come through integrated designs incorporating the use of membranes and other breakthrough recovery technologies.

B.1.1 CO_2 Separation Using a Selective Ceramic Membrane

The water-gas shift (WGS) reaction can increase the H_2 content of a syngas, but the reaction is equilibrium-limited. The fact that the reaction is equilibrium-limited means that the reaction is capable of going in either the forward or reverse direction. That is, it is also possible for CO_2 and H_2 to combine to form carbon monoxide (CO) and water, as steam, under conditions that are favorable for this backward reaction.

One approach for overcoming this limitation is to use a reactor in which the walls are CO_2-permeable, allowing the CO_2 to be removed from the system and the reaction to continue:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The WGS reactor has catalyst-filled ceramic tubes with a membrane that is selectively permeable to CO_2. As gasifier fuel gas passes through the WGS reactor, CO_2 diffuses through the membrane allowing the reaction to approach completion. This process generates a hydrogen-rich fuel stream, while simultaneously producing a pure CO_2 stream for sequestration.

A current project sponsored by NETL is developing a technique for depositing hydrotalcite onto a ceramic membrane suitable for studying the CO_2 separation concept with the WGS reaction in an IGCC system (NETL, 2003). The hydrothermal and chemical stability in a simulated WGS reaction environment will be evaluated to confirm the inert material properties of the ceramic membrane. Then, a membrane reactor (MR) study will be performed to demonstrate the benefit offered by this membrane. Finally, process feasibility will be demonstrated in a test module, and an economic evaluation will be performed to estimate the positive effect of using a WGS-MR in IGCC coal-fired power plants.

This project will produce a hydrogen-rich gas that is at high pressure and high temperature and that contains significant quantities of steam, making it highly suitable for direct firing in a gas turbine with high efficiency. The use of an improved WGS-MR with CO_2 recovery capability is ideally suited for integration into the IGCC power generation system. Thus, the hydrogen (at high pressure and CO_2-free) produced from the IGCC can be used as a product for power generation via a turbine or a fuel cell, or it can be used as a reactant for production of fuels and chemicals.

In another project, which was awarded by NETL in 2004, researchers at the University of Minnesota will develop a new method for making extremely thin, high-temperature, hydrogen-selective silica membranes from byproduct materials (NETL, 2004l). The membranes, called molecular sieves, work like filters with uniquely designed, ultra-small pores that allow only hydrogen molecules to pass through, leaving behind a CO_2-rich gas for sequestration. Such membranes will potentially be used in future fossil-fueled power plants that produce hydrogen under conditions of high temperatures and pressures.

B.1.2 CO_2 Separation through the Formation of Hydrates

Another approach for decarbonizing a syngas utilizes the formation of CO_2 hydrates to remove CO_2 from a gas stream. Under suitable conditions, CO_2 can form hydrates, which are ice-like complexes of water and CO_2 molecules. The CO_2 hydrates are similar to methane hydrates, in which a methane molecule is enclosed in a cage of water molecules. Because viable options for sequestration or reuse of CO_2 are expected to involve transport through pipelines and/or direct injection of high-pressure CO_2 into various repositories, a process that can separate CO_2 at high pressures and minimize recompression costs will offer distinct advantages.

An R&D project sponsored by NETL addresses the issue of CO_2 separation from shifted syngas at elevated pressures using a low-temperature process (NETL, 2004d). The goal of this project is to construct and operate a pilot-scale unit utilizing the hydrate process for CO_2 separation. The objectives of current work in this area are to: (1) carry out further laboratory-scale tests of the CO_2 hydrate concept, including extended continuous-flow tests and component tests; (2) conduct an engineering analysis of the concept, and develop updated estimates of the process performance and cost of carbon control; and (3) use data developed in the lab to design and build a pilot plant using a slipstream in an operating IGCC plant. Future efforts will consist of a pilot demonstration of the process in the IGCC plant.

The hydrate process will provide a high-pressure/low-temperature system for separating CO_2 from shifted syngas in an economical manner. The process can be adapted to an existing gasification power plant for CO_2 separation during production of syngas. Ultimately, the process will result in a residual concentrated stream of hydrogen capable of fueling zero-emission power plants of the future and a concentrated CO_2 stream available for use or sequestration.

B.1.3 CO_2 Separation Using Polymer Membranes

Polymer membranes are employed in many industrial gas separation applications, including the production of high-purity nitrogen, natural gas, dehydration and removal of acid gases, and hydrogen recovery from process streams. Many gas separation applications require materials that are stable at high temperatures and pressures. Polymeric materials currently in commercial use have thermal and mechanical limits too low for such applications. Hence, there is a need for membrane materials that can operate under more extreme conditions for extended periods of time while providing an acceptable level of performance (Klara and Srivastava, 2002 and DOE, 1999). Organic polymer membranes have superior selectivity, while inorganic membranes have superior permeability and stability. Thus, the development of hybrid organic and inorganic membranes may potentially yield the advantages of both types of membranes (NETL, 2004i).

In a project sponsored by NETL, collaborators, including Los Alamos National Laboratory and Idaho National Energy and Engineering Laboratory, are developing a high-temperature polymeric membrane that will exhibit selectivity for CO_2 at an order of magnitude higher than current membranes (NETL, 2004e). The project will focus on the separation of CO_2/CH_4, CO_2/N_2, and H_2/CO_2 gas pairs, which represent separations that are industrially and environmentally important. The major objective of the project is the development of polymeric materials that achieve the important combination of high selectivity, high permeability, and mechanical stability at high temperatures and pressures.

The development of high temperature polymeric-metallic composite membranes for CO_2 separation at temperatures of 100-450°C and pressures of 10-150 bar will provide a pivotal achievement with both economic and environmental benefits. This technology could further reduce the cost of CO_2 sequestration by providing a CO_2 stream at higher pressures than existing technologies, thereby reducing compression costs significantly.

B.2 POST-COMBUSTION CAPTURE

The following are examples of R&D efforts and pilot projects for post-combustion capture sponsored by NETL.

B.2.1 Absorption with Potassium Carbonate

Expanding on bench-scale modeling and pilot-scale experiments, the University of Texas is researching an alternative alkanolamine sorbent (NETL, 2004f). In early experiments, the promotion of potassium carbonate (K_2CO_3) with amines, such as K_2CO_3 in solution with catalytic amounts of piperazine (PZ), exhibited an absorption rate comparable to MEA. Studies also indicate that PZ has a significant reaction rate advantage over other amines as additives. The latest improved process uses a highly reactive solvent that absorbs CO_2 three times faster than MEA and requires as much as 40 percent less energy per unit of CO_2 captured. The process model will be validated by a pilot-plant study to optimize solvent rate, stripper pressure, and other parameters.

B.2.2 Ionic Liquids as Novel Carbon Dioxide Absorbents

In a project awarded by NETL in early 2004, the University of Notre Dame will focus on the development of liquid absorbents that fall within a relatively new class of compounds called ionic liquids (NETL, 2004l). Ionic liquids are typically organic salts that, in their pure state, are liquid under atmospheric conditions at room temperature. They have unusual properties that suggest they could be extremely effective as CO_2 absorbents, possibly replacing current amine-based technology to capture CO_2 from power plant stacks. Unlike amines, which are corrosive and costly to operate, organic salts are typically benign, and can be disposed of in landfills. Building upon and extending their previous work with other chemicals, the researchers will use computer modeling to design and evaluate ionic liquids to determine their affinity for capturing CO_2. They will also assess the economics of different ionic liquids against conventional absorbents.

B.2.3 Dry Regenerable CO_2 Sorbents

Another approach to CO_2 capture employs dry scrubbing by chemical adsorption with a dry sorbent. Such a sorbent can remove CO_2, be regenerated to produce a concentrated stream of CO_2, and be returned to capture more CO_2 in a cyclical process. This process can have economic advantages compared to commercially available wet-scrubbing amine processes. NETL has pioneered R&D to identify dry, regenerable sorbents that can be used for CO_2 capture. Preliminary micro-reactor tests with sodium carbonate have indicated that absorbing CO_2 and steam to form bicarbonate, with subsequent regeneration to the carbonate, is a viable process. Because sorbent regeneration uses waste heat, the power requirement for CO_2 capture is relatively small (Klara and Srivastava, 2002).

In one R&D project, the Research Triangle Institute and Church and Dwight, Inc. are developing an innovative process for CO_2 capture that employs a dry, regenerable sorbent (NETL, 2003a). The goal of this project is to develop a simple, inexpensive process to separate CO_2 as an essentially pure stream from a fossil fuel combustion system. The proposed process can also be used to capture CO_2 from gasification streams at high temperature. Sorbents being investigated, primarily alkali carbonates, are converted to bicarbonates through reaction of CO_2 and water vapor. Sorbent regeneration produces a gas stream containing only CO_2 and water. The water may be separated out by condensation to produce a pure CO_2 stream for subsequent use or sequestration. Future efforts will be aimed at optimizing the process to capture additional CO_2 without requiring additional power.

B.2.4 Pressure and/or Temperature Swing Adsorption

Selective separation of CO_2 can be achieved by the preferential adsorption of the gas on high-surface area solids. Conventional physical adsorption systems are operated in pressure swing adsorption (PSA) and temperature swing adsorption (TSA) modes. In PSA, the gas is absorbed at a higher pressure; then pressure is reduced to desorb the gas. In TSA, the gas is absorbed at a lower temperature; then the temperature is raised to desorb the gas. PSA and TSA are some of the potential techniques that could be applicable for removal of CO_2 from high-pressure gas streams, such as those encountered in IGCC (NETL, 2002).

B.2.5 Electric Swing Adsorption

Electric Swing Adsorption (ESA) is an advanced separation system for CO_2 removal from syngas being developed for use with the gasification of low hydrogen-to-carbon ratio fuels, such as petroleum coke. Oak Ridge National Laboratory has developed a novel process, which adsorbs CO_2 on a carbon substrate. After saturation of the carbon fiber adsorbent with CO_2, immediate desorption of the adsorbed gas is accomplished by applying low voltage across the adsorbent. This technology is being developed to remove CO_2 from the exhaust gas of a conventional combined cycle turbine. Calculations based on adsorption data indicate that it should be possible to develop an improved CO_2 separation process using this method (Klara and Srivastava, 2002).

B.2.6 Gas-Separation Membranes

Gas-separation membranes are of many different types, and although the effectiveness of only a few of these types in separating and capturing CO_2 has been demonstrated, their potential is generally viewed as effective. Gas separation is accomplished via interaction between the membrane and the gas being separated. For example, polymeric membranes transport gases by a solution-diffusion mechanism (i.e., the gas is dissolved in the membrane and transported through it by a diffusion process). Polymeric membranes, although effective and inexpensive, typically achieve low gas transport flux and are subject to degradation. Considerable R&D is required to realize the potential of membranes for separation and capture of CO_2, particularly at higher temperatures and pressures. R&D on polymeric membranes is essentially restricted to changing the composition of the polymer to increase the dissolution and diffusion rates for the desired gas components out of the gas stream and through the membrane. Experience shows an apparent limit to the efficacy of polymeric membranes. Inorganic membranes may be developed to reform fuels to mixtures of hydrogen and CO_2, and to separate the hydrogen with the remaining CO_2 recovered in a compressed form. Major issues include capital cost and membrane stabilization in corrosive gases for coal use (DOE, 1999).

NETL awarded a project in early 2004 that will develop a novel membrane for controlling CO_2 emissions from fossil fuel power plants (NETL, 2004l). Researchers at the University of New Mexico in collaboration with T3 Scientific will develop a new, dual-functional membrane that will use both the pore structure of the membrane, and an amine chemical adhered to the membrane, to increase the removal of CO_2 from fossil-fueled power plants. Researchers anticipate that the strong interactions between the CO_2 molecules and the amine-coated membrane pores will help spread the CO_2 on the pore walls and block other gases, such as O_2, N_2, and S_2O, that are also present in power plant stacks. The new membrane is expected to exhibit higher CO_2 selectivity than other types of silica-based membranes that separate CO_2 based only on the difference in pore size. This new membrane-based CO_2 capture process may be an attractive alternative to costly amine-based absorption processes.

B.2.7 Novel Microporous Metal Organic Frameworks

NETL awarded a project in early 2004 that will involve a collaborative effort among United Oil Products LLC, the University of Michigan, and Northwestern University to discover novel microporous metal organic frameworks (MOFs) suitable for CO_2 separation (NETL, 2004l). MOFs are hybrid organic/inorganic structures at the nanoscale (submicroscopic) to which CO_2 will stick. Researchers plan to use molecular modeling on computers to design, tailor, and assess MOFs with the best properties for adsorbing CO_2, and to predict structures of new MOFs. Successful completion of this project will lead to a low-cost, novel sorbent to remove CO_2 from the gases emitted from power plant stacks.

B.2.8 Co-Sequestration of CO_2 with SO_2 and NO_X

DOE-NETL's Carbon Sequestration Program has a goal to develop by 2015, to the point of commercial deployment, systems for the direct capture and sequestration of greenhouse gas and criteria pollutant emissions from fossil fuel conversion processes that results in near-zero emissions. The goal also states that these systems should approach no net cost increase for energy services when any value-added benefits are factored in.

As part of the plan to achieve that goal for existing pulverized coal-fired boilers, DOE-NETL has initiated preliminary R&D scoping engineering studies to evaluate the feasibility of several processes that would sequester CO_2 and other criteria pollutants. One approach under evaluation is the use of oxygen fired combustion with flue gas recycling. This process maintains a normal temperature in the furnace, resulting in a CO_2-rich stream exiting the boiler that is ready for sequestration with only minimal gas conditioning. That project addresses both possibly retrofitting boilers at existing coal-fired power plants, such that CO_2 capture eliminates the need for N_2/CO_2 separation and sulfur separation, and permits more economical CO_2 recovery than competing amine systems. In another economic and engineering scoping study, CO_2 capture from pulverized coal boilers using aqueous ammonia is being evaluated. Aqueous ammonia has been used in several commercial power plant SO_2 capture applications, and a commercial-scale demonstration of multi-pollutant control for scrubbing SO_2, NO_X, and mercury from flue gas. As such, incorporating CO_2 capture within the aqueous ammonia scrubber system (via CO_2 capture and solvent regeneration by chemical reaction cycling between ammonium carbonate and bicarbonate) presents a potentially advantageous multi-pollutant control option for CO_2. As both of these projects are in the early stages of R&D, no model project was developed in this PEIS for the co-sequestration of CO_2 with criteria pollutants.

B.3 CO_2 CAPTURE PROJECT

In collaboration with eight major international energy companies, DOE is sponsoring the CCP with the goal of developing breakthrough technologies aimed at substantially reducing the costs of CO_2 capture and geologic storage (NETL, 2003b). The CCP consortium is led by BP-Amoco, and its members include ChevronTexaco, ENI, Norsk Hydro, PanCanadian, Shell, Statoil, and Suncor. In addition to the U.S. program, the CCP is performing separate, but complementary projects, which are being sponsored by the European Union and Norway. The CCP team collectively accounts for approximately 32 percent of all oil and 17 percent of all gas production in the U.S., and 28 percent of oil and 17 percent and gas production by Organization for Economic Cooperation and Development (OECD) countries.

The project involves an integrated CO_2 capture and sequestration undertaking. For the CO_2 capture effort, the project objectives are to perform benchtop R&D (engineering studies, computer modeling, and laboratory experiments) to prove the feasibility of advanced CO_2 separation and capture technologies. This will specifically target post-combustion capture, pre-combustion decarbonization, and oxyfuel combustion. By conservative estimates, the technology developed in the project could reduce the emissions of the CCP participants by 10 MMT of carbon per year. When applied more broadly in the energy industry, the technology could reduce emissions by up to 140 MMT of carbon per year.

Additional R&D Efforts

In addition to the projects summarized in the preceding paragraphs, NETL is sponsoring additional R&D efforts by universities and industries, and by using its own scientists and facilities (NETL, 2004b, 2002a, 2002b, 2002c, 2002d). Examples include:

- Carnegie Mellon University is developing an integrated modeling framework to evaluate alternative carbon sequestration technologies for electric power plants.
- Princeton University is developing a conceptual design of optimized fossil energy systems with capture and sequestration of CO_2.
- Siemens Westinghouse Power Corporation is modifying the design of the tubular solid oxide fuel cell (SOFC) module to incorporate an afterburner stack of tubular oxygen transport membranes, which will oxidize the SOFC-depleted fuel in the anode exhaust to CO_2 that can then be easily separated.
- NETL designed and constructed the Modular Carbon Dioxide Capture Facility (MCCF), which mimics coal-fired combustion processes that produce electricity and can be fired with natural gas, coal, or a combination of the two. The MCCF can be used to test new capture technologies on coal combustion flue gas and, additionally, on process gas from advanced fossil-fuel conversion systems, such as coal gasification (NETL, 2003c).
- The Carbon Sequestration Science Focus Area (CSSFA) at NETL serves as the focal point for all carbon sequestration R&D activities performed with in-house resources sponsored primarily by the Office of Fossil Energy. CSSFA conducts research ranging from fundamental studies to small-scale proof-of-concept research on selected processing options. Systems analysis via computer modeling and simulation of approaches to carbon sequestration will be developed in-house for use in evaluating the various approaches (NETL, 2002a).

B.4 OXYGEN-FIRED COMBUSTION

Oxygen-fired combustion burns fuel in enriched air or pure oxygen to produce a concentrated stream of CO_2. It presents significant challenges but provides high potential for technology break-throughs and step-change reduction in CO_2 separation and capture costs. Currently, there are no oxygen-fired PC plants in commercial operation. Among the barriers and issues are the facts that oxygen generation is expensive, oxygen combustion consumes three times more oxygen per kilowatt-hour (kWh) of electricity generation than coal gasification followed by combustion of the syngas in air, and combustion of fuels in pure oxygen occurs at temperatures too high for existing boiler or turbine materials. The economics of oxygen firing and IGCC can be improved by advanced oxygen production technology. New air separation processes using high-temperature oxygen ion transport ceramic membranes are being developed. For oxygen-fired combustion, the integration of an oxygen transport membrane (OTM) for oxygen production with the combustion system can provide cost-effective capture of CO_2 from power plants (NETL, 2004a and 2004b; Klara and Srivastava, 2002).

B.4.1 Advanced Oxyfuel Boilers and Process Heaters for Cost-effective CO_2 Capture

NETL, Praxair, and Alstom Power are collaborating on a project that will advance the integration of OTMs into oxy-fired boilers from the bench scale to the point-of-readiness for engineering scale-up (NETL, 2004g). The development of a novel oxy-fuel boiler will significantly reduce the complexity of CO_2 capture, drastically reduce the cost of carbon sequestration, and offer increased thermal efficiency and reduced pollution emissions. Gasification plants that integrate OTM technology will have higher efficiency, lower cost of electricity, and lower emissions of pollutants compared to a conventional cryogenic air separation unit. The main objectives of the project are: (1) to develop and demonstrate the integration of a novel ceramic OTM with the combustion process to enhance boiler efficiency and CO_2 recovery, and (2) to develop a conceptual design for a laboratory scale boiler simulator. The project has developed a ceramic membrane and seal assembly for thermal integration between the high temperature membrane and the combustion process. Current efforts focus on laboratory-scale evaluations for the integration of OTM with the combustion process.

B.4.2 Oxygen Firing in Circulating Fluidized Bed (CFB) Boilers

The goal of a project involving NETL, Alstom Power, ABB Lummus Global, and others is to conduct economic evaluations of CO_2 recovery using a newly constructed circulating fluidized bed (CFB) combustor burning various solid fuels with a mixture of oxygen and recycled flue gas, instead of air (NETL, 2004h). In Phase 1 of the project, a performance analysis of the base case (air-fired) CFB was completed to determine which of the new concepts in a CFB are technically feasible and have the potential for reducing the target cost of carbon emissions avoided. In Phase 2, the project will generate a refined technical and economic evaluation of the most promising concept, based on data from proof-of-concept testing. Work has been completed on the performance analysis of three advanced O_2-fired CFB concepts, a high-temperature carbonate regeneration process, a chemical looping concept, and two IGCC cases (a base case without CO_2 capture and one with a WGS reactor to capture CO_2). Phase 2 pilot testing has been initiated, and the test facility is being modified to perform the planned pilot tests.

B.4.3 Oxygen-enriched Combustion

CanMet Energy Technology Center and a consortium of industrial companies, including McDermott Technology, Trans Alta Corp., Saskatchewan Power, Air Liquide Canada, Nova Scotia Power, Ontario Power Generation, and Edmonton Power are conducting pilot-scale tests of oxygen enhanced coal combustion with the objective of lowering the cost of retrofit systems (NETL, 2005b).

B.5 ADVANCED CONVERSION

There is a limited number of other promising concepts for CO_2 capture, none of which is yet at a commercial or demonstration phase. One example involves the indirect combustion of coal, sometimes referred to as chemical looping, to provide oxygen for combustion by a metal oxide, rather than by air. TDA Research and Louisiana State University are collaborating on such a project for NETL. These researchers intend to develop a method using gasified coal or natural gas to reduce a metal-oxide sorbent, producing steam and high pressure CO_2. The steam will be condensed into water, and the CO_2 will be sequestered. The reduced metal-containing solid will be transferred to a second fluidized bed reactor, where it will be re-oxidized with air. This exothermic reaction heats the oxygen-depleted air, which is used for power production. Sorbent materials with desirable properties will be developed and tested, and the economics and emissions performance of integrated electricity generation systems based on the various sorbents will be estimated (Klara and Srivastava, 2002).

B.6 SEQUESTRATION IN COALBEDS

B.6.1 Effects of Temperature and Gas Mixing in Underground Coalbeds

NETL is sponsoring a bench-scale research project by Oak Ridge National Laboratory that intends to measure the behavior of CO_2, methane, and nitrogen gas mixtures at elevated temperatures and pressures (Blencoe, et al., 2004). The project will focus on temperatures (25-200º C) and pressures (1-300 bars) that are relevant to CO_2-enhanced CBM recovery. Measurements will be taken for the density and viscosity of the gas mixtures and coal swelling and shrinkage in brine-mixed combinations of the three gases. The project also intends to acquire additional technical data needed on the geochemical reactions that will occur when CO_2 is injected into deep, unmineable coalbeds.

B.6.2 Enhancing Methane Production in Unmineable Coalbeds while Sequestering CO_2

Oklahoma State University is leading a bench-scale effort to investigate and test the ability of injected CO_2 to enhance CBM production (NETL, 2002e). The effort will collect data from coals of various physical properties at various temperatures, pressures, and gas compositions to identify the conditions for which proposed sequestration applications are most attractive. The overall goal of the project is to develop predictive models for describing the adsorption behavior of gas mixtures on coal over a complete range of temperature, pressure, and coal types.

The project team is developing mathematical models to describe the observed adsorption behavior accurately. The combined experimental and modeling results will be characterized to provide a sound basis for performing reservoir simulation studies. These studies will evaluate the potential for injecting CO_2 or flue gas into coalbeds to simultaneously sequester CO_2 and enhance CBM production. Future computer simulations will assess the technical and economic feasibility of the proposed process for specific candidate injection sites.

Thus far, the project has characterized several types of coals by their ability to adsorb nitrogen, methane, and CO_2. Adsorption of CO_2 and methane at low pressure was studied in a laboratory apparatus, and the project has made significant progress in improving the predictive capability of models. The research will eventually determine how much methane can be displaced by a given amount of CO_2.

B.6.3 Physics and Chemistry of CO_2 Sequestration and CBM Production in Coal Seams

Pennsylvania State University is leading a research team on a project intended to provide guidelines for the drilling of new CBM production wells (NETL, 2002f). The results will enable field engineers to determine if cases of poor CO_2 sequestration and/or low methane production can be attributed to non-ideal coalbed temperatures and/or depths, or to other factors.

Thus far, the project has developed a method for simultaneously accounting for the heats and amounts of CO_2 and methane adsorption/desorption and the extents of dehydration. Mathematical methods for resolving complex temperature relationships have also been developed, and the researchers found an apparent correlation between hypothetical extents of coal dehydration and predicted relative viscosities of water in the narrow capillaries and pores of coal.

The project developed a laboratory system for the measurement of adsorption isotherms. The system was pressure-tested and successfully employed to generate data along with a derived equation used to separate the actual surface adsorption from the effects of coal swelling on the isotherm shape. The extent of actual physical adsorption was determined, the heats of adsorption were calculated, and the values were found to agree within 10 percent of each other. The project has resulted in the development of a new theory of coal swelling and how the CO_2 adsorption process affects swelling.

B.6.4 Geologic Screening Criteria for Sequestration of CO_2 in Coalbeds (Alabama)

The Geological Survey of Alabama and its partners are conducting research to determine the amount of CO_2 that can be stored in the Black Warrior basin of Alabama (NETL, 2002g). The CBM fairway of the Black Warrior basin is an excellent location to develop screening criteria and procedures. According to the EPA, Alabama ranks 9th nationally in CO_2 emission from power plants, and two coal-fired power plants are located within the CBM fairway. More than 34 billion cubic meters of CBM have been produced from the Black Warrior basin, which ranks second globally in CBM production. Production is now leveling off, and ECBM recovery has the potential to offset impending decline and extend the life and geographic extent of the fairway far beyond current projections.

The project will quantify CO_2 sequestration potential in Black Warrior CBM fairway, develop a screening model that has wide applicability, and apply the screening model to identify favorable demonstration sites for CO_2 sequestration. The partners have performed subsurface geological analyses and collected hydrologic and geothermic data from more than 2,800 well logs. Preliminary results confirm that coal can adsorb significantly more CO_2 than methane while having relatively little capacity to adsorb nitrogen.

B.6.5 Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds (New Mexico and Colorado)

Advanced Resources International (ARI) and its partners are using the only long-term, multi-well ECBM projects that currently exist in the world to evaluate the feasibility of storing CO_2 in deep, unmineable coal seams (NETL, 2003d). The two existing ECBM pilot sites are located in the San Juan Basin in northwest New Mexico and southwest Colorado. The knowledge gained studying these projects is being used to verify and validate gas storage mechanisms in coal seams, and to develop a screening model to assess CO_2 sequestration potential in other promising coal basins of the U.S.

Two field pilot sites, the Allison Unit (operated by Burlington Resources) and the Tiffany Unit (operated by BP Amoco), are demonstrating CO_2 and N_2 ECBM recovery technology, respectively. The interest in understanding how N_2 affects the process has important implications for power plant flue gas injection, because N_2 is the primary constituent of flue gas. As the current cost of separating CO_2 from flue gas is very high, this project is evaluating an alternative to separation by sequestering the entire flue gas stream. Another reason for considering CO_2/N_2 is that N_2 is also an effective methane displacer that can improve methane recoveries and further reduce the net cost of CO_2 sequestration. The Allison Unit pilot area, which has been in operation since 1995, includes 16 production wells and 4 injection wells. The Tiffany Unit pilot area, which has been in operation since 1998, consists of 34 production wells and 12 injection wells.

This demonstration project is providing valuable new information to improve the understanding of coal formation behavior with CO_2 injection, as well as the ability to predict results and optimize the process through modeling. The field studies have clearly demonstrated that ECBM via CO_2/N_2 injection and CO_2 sequestration in coal seams is technically feasible. A nationwide assessment indicates that this approach has the potential to sequester 90 billion metric tons of CO_2 and provide an additional 150 trillion cubic feet of gas supply for the U.S. Field and laboratory data have provided important new insights into the process, such as the tendency for coal to swell when it comes into contact with CO_2, which reduces permeability and injection rates. The research has also increased the understanding of processes for methane displacement by CO_2. These findings are being incorporated into a software model that can be used by industry to screen site-specific sequestration opportunities in coalbeds.

B.6.6 Sequestration of CO_2 in Unmineable Coal Seams with ECBM Recovery (West Virginia)

In another project sponsored by NETL, CONSOL Energy, Inc. will demonstrate a novel drilling and production process that reduces potential methane emissions from coal mining, produces usable methane, and creates a sequestration sink for CO_2 in unmineable coal seams (NETL, 2005a). CONSOL's project will employ a slant-hole drilling technique to drain CBM from a minable coal seam and an underlying unmineable coal seam. Upon drainage of 50 to 60 percent of the CBM, some of the wells will be used to inject and sequester CO_2 in the unmineable seam while stimulating additional methane production. The primary goal of this project is to evaluate the effectiveness and economics of carbon sequestration in an unmineable coal seam. Dewatering and degassing of wells have begun. The West Virginia Department of Environmental Protection has permitted the Central Well site's modified wells. The operators performed an environmental assessment under NEPA (NETL, 2002o) and DOE issued a Finding of No Significant Impact (FONSI).

B.7 ENHANCED OIL RECOVERY AND ENHANCED GAS RECOVERY

Current R&D projects and large-scale field tests are described in the following paragraphs.

B.7.1 The GEO-SEQ Project – Geological Sequestration of CO_2

A consortium of national laboratories is conducting the GEO-SEQ Project, including Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, and Oak Ridge National Laboratory, as well as educational institutions, and private industry firms (LBNL, 2004). The goals are to reduce the cost of sequestration, to develop a broad suite of sequestration options, and to ensure that long-term sequestration practices are effective and do not introduce new environmental problems. The project includes eight tasks intended to achieve these goals, including the Frio Test Well (see Section 3.2.2.3). With respect to EOR sequestration, the project seeks to develop methods for simultaneously optimizing sequestration of CO_2 in depleted oil and gas fields and increasing oil and gas production. Results will lay the groundwork for rapidly evaluating performance at candidate sequestration sites, as well as monitoring the performance of CO_2 in enhanced oil and gas recovery. The GEO-SEQ Project also includes tasks that are more closely associated with MM&V (see Section 3.2.3).

B.7.2 Weyburn CO_2 Sequestration Project (Canada)

The Weyburn oil field, located on the northwestern rim of the Williston Basin in the southern part of Saskatchewan Province, Canada, was first drilled in 1954. Today, about 650 production and water injection wells are operated by EnCana Resources (formerly PanCanadian Resources). During its lifetime, the 70-square mile oil field has produced some 55 million cubic meters of oil from primary and water-flood production. In October 2000, EnCana began EOR efforts using CO_2 to extend the life of the Weyburn field by more than 25 years, anticipating the extraction of 130 million barrels of oil, or more, from the depleted field. A daily supply of 2.7 million cubic meters of waste CO_2 (95 percent pure) has been supplied to the Weyburn oil field from the Great Plains Synfuels Company in Beulah, North Dakota. Since its inception, the original project sponsors have been joined by DOE, the European Union, the Alberta Government, the Japanese ENAA, and industrial sponsors, including BP, ChevronTexaco, TotalFinaElf, Dakota Gasification Co., TransAlta Utilities, SaskPower and Nexen. Now in its fifth year, the Weyburn Project represents a unique opportunity for these governments and industries to collaborate on the largest emissions-reduction project to date (Fitzpatrick, 2004 and NETL, 2004m).

Among its key aspects, the Weyburn Project is using waste CO_2 for a miscible flood EOR project and is studying the behavior of the CO_2 in the depleted oil field. Over the project's lifetime, approximately 20 MMT of CO_2 will be stored in the Weyburn oil field; recycling and eventually storing 0.3 percent of the world's total annual CO_2 emissions, which is an amount equivalent to emissions generated by the state of Maryland.

The Weyburn Project is attempting to answer questions that have not been considered in most EOR operations, such as what happens to the stored CO_2, how much can be stored, as well as the relative merits of storage with enhanced oil production. Researchers are gathering information before and after CO_2 flooding to assess the effectiveness of CO_2 as an EOR agent and to analyze the conditions and behavior of the CO_2 in the oil field. Another element of the study is determining yield and storage capacity to fully realize cost effectiveness, i.e., determining the potential CO_2 storage capacity of the reservoir for every enhanced barrel of oil produced.

Until now, vague knowledge of the geologic formation and activities, combined with the constant fluctuation of oil prices, has made predicting the economic success of EOR projects difficult. But the historical data on the Weyburn oil field is expected to provide unique insights for a sound economic model of current and future CO_2-EOR/sequestration efforts. The efforts of this and other EOR/sequestration projects are intended to give worldwide support to the notion that geologic storage is a safe, environmentally acceptable means of CO_2 mitigation.

The major permitting activity for this project is related to a nearly 200-mile pipeline needed to transport CO_2 from Dakota Gasification in the United States to the Weyburn field in Canada. After a public hearing, Canada's National Energy Board approved the application from Souris Valley Pipeline in October 1998. The Federal Energy Regulatory Commission approved the pipeline in the U.S., which travels west from Dakota Gasification and then north following oil reservoirs. This path took the pipeline through North Dakota's cherished badlands, which raised concerns about the land disturbance for the corridor. Basin Electric employees and others worked proactively to restore the land disturbed by the buried pipeline, in compliance with U.S. DOT rules. Also, Haines Construction Company, the pipeline contractor, used backhoes instead of a conventional trencher, which enabled topsoil to be separated and replaced on top. Six years later, the pipeline route is difficult to discern in many places during aerial surveys.

B.7.3 Sequestration of CO_2 in West Pearl Queen Field (New Mexico)

Sandia National Laboratory and Los Alamos National Laboratory have partnered with Strata Production Company to investigate downhole injection of CO_2 into a depleted oil reservoir, the West Pearl Queen Field in New Mexico (NETL, 2003e). This project is using a comprehensive suite of computer simulations, laboratory tests, and field measurements to understand, predict, and monitor the geochemical and hydrogeologic processes involved. The overall objective of this project is to better understand, predict, and monitor CO_2 sequestration in a depleted sandstone oil reservoir. Injection into this reservoir was through an inactive well, while a producing well and two shutoff wells are being used for monitoring. Approximately 2,100 tons of CO_2 - equivalent to one day's emissions from an average coal-fired power plant - have been injected into the formation. After the CO_2 has been allowed to "soak" into the reservoir rock, a second 3-D seismic survey will be taken. These observations will begin to tell scientists the fate of the CO_2 plume and will be used to calibrate, modify, and validate modeling and simulation tools. The project received a categorical exclusion under NEPA based on the fact that it was a small-scale, limited-duration injection deep underground.

B.7.4 In Salah Gas CO_2 Storage Project

In Salah Gas (ISG) is a joint venture project between BP, Statoil, and Sonatrach, involving a phased development of eight gas fields located in the Algeria Central Sahara, with a contracted sales gas stream of 9 billion m^3/year. These gas fields contain CO_2 concentrations ranging between 1 and 9%, which is above the export specification of 0.3%, therefore requiring CO_2 removal facilities. ISG has made a discretionary investment to enable compression and re-injection of the produced CO_2 gas stream, up to 70 MMscfd or 1.2 $MMTCO_2$, for geologic storage. Production operations and CO_2 re-injection began in

August 2004. The ISG project represents the first commercial scale injection of CO_2 into an active producing natural gas reservoir (Riddiford, et.al., 2005).

The storage scheme has the CO_2 re-injection directed into the aquifer region in the carboniferous reservoir, down-dip of the main hydrocarbon accumulation. To achieve a successful CO_2 injection scheme, a number of peripheral injection wells were required to mitigate potentially high injection pressures, access the peripheral reservoir volumes for sub-surface storage, and manage the placement of the injected CO_2. Effective placement of the CO_2 is important, with geosteering of the wells to target high porosity, high permeability intervals. It requires that the injected gas, which is driven by gravitational forces and the pressure sink associated with production, is retained within the aquifer zone and does not enter the main field area until after it has been depleted and abandoned. This is projected to be after 25 to 30 years of production.

The ISG project is expected to contribute to setting precedents for monitoring, regulation, and verification of geologic storage, and establish CO_2 capture and storage as eligible for GHG mitigation credits. Monitoring at In Salah Gas will serve a number of purposes:

- Enable optimization and management of hydrocarbon production (rates and reserves over time) by quantifying the impact of CO_2 re-injection and reducing uncertainties over time.
- Develop a detailed understanding of the behavior of the CO_2 storage with a view to reducing uncertainties in predictions of long-term storage performance.
- Test and demonstrate the technologies necessary for early detection of seepage of CO_2 out of the primary containment to enable intervention and maintain the integrity of long-term storage.

The project will require extensive monitoring of the storage site and overburden using a range of existing and novel technologies, including repeat 3D seismic, well-bore aquifer, and surface monitoring, plus extensive modeling of the whole system (Riddiford, et.al., 2005).

Examples of the MM&V technologies planned for implementation as part of the ISG joint industry program include the following (Wright, et.al., 2005):

- Sample analysis of water, gas, and solids
- Noble gas tracers injected with the CO_2
- Pressure surveys, surface and down-hole (static and interference)
- Electric logs (production, seismic profiles, and tomography)
- Gravity baseline, soil-gas survey, micro-seismic and tilt meters
- Meteorology and microbiology
- 4D seismic
- Aquifer monitoring well with oriented cap rock core and cuttings analysis
- Down-hole gravity and geo-mechanical monitoring
- Surface eddy flux co-variance data

B.8 SEQUESTRATION IN SALINE FORMATIONS

Current R&D projects and large-scale field tests are described in the following paragraphs.

B.8.1 Sleipner – The World's First Commercial-Scale CO_2 Capture and Storage Operation (Norway)

Statoil's Sleipner West Gas Field in the Norwegian North Sea is one of the world's largest producers of natural gas, but the produced gas (9 percent CO_2) does not meet end use or pipeline specifications. To reduce the CO_2 content to the 2.5 percent product specification level, while meeting Norwegian CO_2 emissions targets (a Norwegian CO_2 tax was instituted in 1995), a sequestration strategy was adopted in October 1996. Statoil manages the research at Sleipner, which is coordinated by the International Energy Agency's (IEA) Greenhouse Gas R&D Programme. DOE is a member of this IEA program. Other contributing partners include BP Amoco, ExxonMobil, Norsk Hydro, Saga, and Vattenfall. International government and industry organizations are providing research and technology.

In this project, unwanted CO_2 is stored 1,000 meters beneath the seabed in a saline formation. As a result of this CO_2 storage operation, Norway's CO_2 emissions are reduced by about 3 percent per year. Since the project's inception, 1 MMT of CO_2 have been stored each year, which is an amount equal to the CO_2 emissions of a typical 150 mega-watt (MW) coal-fired power plant located in the U. S.

Two towers, each about 20 meters high, are located on the Statoil North Sea platform. In the first tower, the CO_2 is captured by amine absorption and compressed. Energy freed during the amine process is used to run two 3 MW generators, thereby providing power for the platform. Next, the CO_2 is stripped from the amine, resulting in injection-ready CO_2. A separate injection well is used to inject the CO_2 into the Utsira aquifer, which is a massive saline sandstone formation with a shale caprock 1,000 meters under the seabed. The hydrocarbon reservoir used for natural gas production lies 3,500 meters below the seabed under the Utsira formation.

It is estimated that the Utsira formation can store up to 600 billion metric tons of CO_2. Hence, the total CO_2 emissions from all of Europe's power plants could be stored in this structure for the next 600 years. While permanent storage cannot be assured, it is estimated that the injected CO_2 will remain in the structure for at least the next several centuries.

B.8.2 Frio Formation Test Well (Texas)

In the first U.S. field test to investigate the ability of saline formations to store GHGs, the University of Texas at Austin is leading a team on a effort (NETL, 2004k) co-sponsored by NETL under the GEO-SEQ Project (see Section 3.2.2.2). The Frio Brine Pilot Experimental Site is located 30 miles northeast of Houston, in the South Liberty oilfield. The site is representative of a very large extent of the geology from coastal Alabama to Mexico, and will provide experience useful in planning CO_2 storage in high-permeability sediments worldwide. The subsurface geology of the region is well known. CO_2 has been successfully injected in the region for EOR, and fluid injection for waste disposal is widely practiced. However, modeling by Lawrence Berkeley National Laboratory (LBNL) has identified some poorly known variables that control CO_2 injection and post-injection migration.

The investigators performed an environmental assessment under NEPA (NETL, 2003m) and a FONSI was issued. As a part of a request for a Class V permit under the Underground Injection Control (UIC) program from the Texas Commission on Environmental Quality, the project developers prepared a high-quality 100-page document describing the geology and hydrology of the injection zone, plans for construction and operation of the injection well, and results from a reservoir modeling effort. The Class V permit request was based on the fact that the Frio area is primarily a depleted oil field, and that the current experiment would be conducted in a saline zone using an undisturbed geologic formation that would provide clearer data and enhanced knowledge. The Class V permit was granted by the state.

The team drilled a 5,753 foot injection well and developed a nearby observation well to study the ability of the high-porosity Frio sandstone formation to store CO_2. In October 2004, the researchers injected 1,600 tons of CO_2 into the formation over a 9-day period. The CO_2 was injected from 5,053 to 5,073 feet below the surface into the saline reservoir contained within a fault-bounded compartment covered by a 200-foot caprock of Anahuac shale.

A variety of methods are being used to monitor the movement of CO_2 in the formation. Before injection, baseline aqueous geochemistry, wire-line logging, cross-well seismic, cross-well electromagnetic imaging, and vertical seismic profiling - as well as two-well hydrologic testing, surface water, and gas monitoring- were completed. These monitoring efforts were repeated at intervals during the injection phase and are continuing with the objective of determining the stability of CO_2 storage in the formation.

Measurements made during this field test will help define the correct values for variables identified by LBNL, and will enable researchers to better conceptualize and calibrate models to plan, develop, and effectively monitor larger scale, longer timeframe injections. The researchers plan to perform follow-on testing with a larger volume of CO_2 and longer term monitoring to determine the formation's capacity to store CO_2 and to identify any potential environmental impacts.

B.8.3 An Investigation of Gas/Water/Rock Interactions and Chemistry

NETL and USGS are planning to lead an experimental study to assess the role of the chemistry of formation water in CO_2 solubility and the role of rock mineralogy in determining the potential for CO_2 sequestration through geochemical reactions (NETL, 2002i). The project would focus on the complex solution and surface chemistry of CO_2 in brines in the presence of host rock and the special types of analyses required to study the reaction kinetics. Carbonate mineral formation/dissolution reactions that may be important in geologic sequestration in deep saline formations will be identified. The kinetics of CO_2 dissolution in the liquid phase and subsequent substrate-water reactions are slow and poorly understood. Therefore, understanding the kinetics of both types of reactions and the processes controlling them is essential to understanding the conversion of CO_2 into stable carbonate minerals.

A compilation of existing brine data from a variety of sources, and a complete statistical analysis of the brine chemistry and other geological parameters associated with saline formations, will be a valuable tool for both experimental and modeling studies of CO_2 sequestration in brines. Currently, NETL is developing a brine database that includes temperature, depth, pressure, and a variety of chemical variables (pH, sodium, iron, chloride, bicarbonate, calcium, magnesium, sulfate, and total dissolved solids) on some 64,000 brines taken from the contiguous U.S. Sources of these data include those provided by the USGS, searches of geoscience literature, state geological surveys, and oil and gas producing companies. Additionally, NETL has instituted a limited field program of brine collection throughout the U.S. This brine sampling is being done in conjunction with other government agencies and oil and gas companies.

B.8.4 Optimal Geological Environments for CO_2 Disposal in Saline Formations in the U.S.

The Bureau of Economic Geology, University of Texas at Austin, is developing criteria to characterize optimal conditions and characteristics of saline formations that can be used for long-term storage of CO_2 (NETL, 2002j). Phase I of this project included identifying drilling locations for CO_2 injection wells and better defining saline formation conditions suitable for CO_2 disposal and sequestration. During Phase II, saline water-bearing formations outside of oil and gas fields were investigated.

Recent R&D efforts have demonstrated the technical feasibility of the process, defined costs, and modeled technology needed to sequester CO_2 in saline formations. One of the simplifying assumptions used in previous modeling efforts is the effect of stratigraphic complexity on transport and trapping in saline formations. Phase III efforts will include field testing of a limited amount of CO_2 injected into a deep saline reservoir within the state of Texas to ascertain the interaction of the gas with the reservoir rock and to monitor the size and shape of the CO_2 plume within the reservoir. Current effort is directed at a field test of injecting a set amount of CO_2 into a deep saline reservoir and monitoring the interaction of the gas with the reservoir and the dispersion of the CO_2 with time.

This project will benefit industry by extending modeling and monitoring capabilities for sequestration into the geologic settings where very large-scale sequestration is feasible in the geographic areas where sequestration is needed. Nonproductive brine-bearing formations below and hydrologically separated from potable water aquifers have been widely recognized as having high potential for very long term (geologic time scale) sequestration of GHGs, and this site will provide a first field-scale testing in this setting. It will also provide a regional U.S. data inventory of saline water-bearing formations.

B.8.5 Chemical Sequestration of CO_2 in Deep Saline Formations in the Midwest United States

Battelle Memorial Institute is leading a consortium of industries and institutions sponsored by NETL in a field study to determine whether the deep rock layers in the Ohio River Valley are suitable for storing CO_2 (NETL, 2003f). The Ohio River Valley is home to the largest concentration of fossil fuel fired electricity generation in the nation. American Electric Power (AEP) owns and operates the Mountaineer Power Plant, which is the host site for the research project. The project involves site assessment to develop the baseline information necessary to make decisions about a potential CO_2 geologic disposal field test and verification experiment at the site. Additionally, the potential for long-term sequestration of CO_2 in deep, regional sandstone formations and the integrity of overlying caprock will be evaluated for future sequestration projects.

Regional-scale assessments in the Midwest and other regions show that there is enormous potential sequestration capacity in sedimentary basins with favorable formation thickness, hydrogeology, seismicity, and proximity to CO_2 sources. However, site-specific tests and characterization are needed to determined injection potential at individual locations. The project is currently in Phase III, which is focused on a site characterization (surface and subsurface) for possible injection of CO_2 into a suitable formation. CO_2 injection is not planned during this phase. However, if studies show that storing CO_2 deep underground in the Ohio River Valley will be safe, practicable, and effective, AEP and its partners will decide whether to go to the next stage, involving active CO_2 injection.

B.8.6 Pioneer Project, American Electric Power (AEP)

AEP is also exploring the possibility of capturing CO2 from its Pioneer Power Plant in New Haven, West Virginia and injecting it into a saline reservoir that underlies the facility. The project is currently in the assessment phase, and CO_2 has not yet been injected. AEP has performed preliminary designs of CO_2 capture and onsite pipeline transport to ensure they do not violate any of the facility's existing permits. Seismic tests of the region have been conducted and a 10,000-foot test well was drilled. These activities were granted a categorical exclusion under NEPA on the basis that they were necessary to acquire data to perform an Environmental Assessment. The West Virginia State Oil and Gas Division granted the well a test well variance under the UIC Program. AEP has undertaken a significant community outreach and education effort in preparation for possible future CO_2 injection.

B.8.7 Reactive, Multiphase Behavior of CO_2 in Saline Formations Beneath the Colorado Plateau

The University of Utah is leading an effort to conduct an in-depth study of deep saline reservoirs in the Colorado Plateau and Rocky Mountain region (NETL, 2002h). These formations serve as natural analogs for CO_2 sequestration in saline formations, and can provide useful data to verify computer models. Small amounts of natural leakage from these reservoirs is occurring, and studying these leaks can provide insight into the environmental problems caused by leaks, the circumstances under which leaks can occur, and how problems can be mitigated. The project also provides for numerical simulation of CO_2 sequestration in these formations, including reactive modeling for chemical reactions between the rocks in the formation and CO_2 (Klara, et al., 2003). The study will enable researchers to determine how much CO_2 can be stored, what happens to the stored gas, and the long-term environmental risks associated with storage.

B.8.8 New Techniques for Injecting CO_2 into Saline Formations

Texas Tech is performing a project sponsored by NETL (Klara, et al., 2003) to develop a well-logging technique to characterize geologic formations, including the quality and integrity of caprock, using nuclear magnetic resonance (NMR). The use of NMR precludes the need for core sampling, and can be performed more quickly and efficiently. The research is directed at identifying suitable sites for CO_2 injection at which controlled hydraulic fracturing can be used to create artificial zones of high permeability. Such actions could significantly reduce the number of wells required for injection.

B.9 SEQUESTRATION IN OTHER NOVEL GEOLOGIC FORMATIONS

Promising but untested reservoir types have significant carbon storage capacity and the potential for value-added hydrocarbon production with CO_2 storage.

B.9.1 Analyses of Devonian Black Shales in Kentucky for Potential CO_2 Sequestration

A project led by the University of Kentucky is investigating the untested concept that black, organic-rich Devonian shales, like coals, could serve as significant geologic sinks for CO_2 (Nuttall, 2004). Devonian shales underlie approximately two-thirds of Kentucky. In these shale formations, natural gas is adsorbed on clay and kerogen surfaces, analogous to methane storage in coalbeds. It has been demonstrated in gassy coal that, on average, CO_2 is preferentially adsorbed, displacing methane at a ratio of 2 for 1. It is believed that black shales may similarly desorb methane in the presence of CO_2.

For this project, drill cuttings from the Kentucky Geological Survey Well Sample and Core Library are being sampled to collect CO_2 adsorption isotherms. Sidewall core samples have been acquired to investigate CO_2 displacement of methane, and an elemental capture spectroscopy log has been acquired to investigate possible correlations between adsorption capacity and mineralogy. The study has shown that CO_2 adsorption capacities at 400 psi range from a low of 19 scf/ton in less organic-rich zones to more than 86 scf/ton in the Lower Huron Member of the shale.

It has been estimated, based on these data, that the Lower Huron Member of the Ohio Shale of eastern Kentucky has the capacity to sequester 5.3 billion tons of CO_2 and that the deeper Devonian shales in Kentucky may hold up to 28 billion tons. If the black shales of Kentucky are shown to be a feasible geologic sink for CO2, their widespread distribution in the Paleozoic basins throughout North America should make them an attractive location for CO_2 storage and enhanced natural gas production (Nutall, 2004).

B.9.2 Sequestration Potential of Texas Low-rank Coals

The Texas Engineering Experiment Station of Texas A&M University is leading a project to investigate the technical and economic viability of CO_2 sequestration in Texas' low-rank coals, and the potential for enhanced CBM recovery (NETL, 2004c). The study will include an analysis of the volumes and composition of Texas power plant flue gases, the detailed characterization of prospective coalbeds, and computer simulation of CO_2 sequestration in the coals.

B.9.3 CO_2 Sequestration in Carbonate Sediments Below the Sea Floor

In a project awarded by NETL in 2004, scientists from Harvard University, Columbia University, Carnegie Mellon University, and the University of California at Santa Cruz will investigate the feasibility of sequestering CO_2 by injecting it below the sea floor in calcium carbonate sediments (NETL, 2004l). These sediments could act as absorbents for the CO_2, but they warrant study because the chemistry, temperature, and pressure below the sea floor are different than in underground sequestration on land. The experiments will use pressurized tanks in a laboratory as a modeling tool to simulate the conditions below the sea floor. The researchers will seek to understand the mechanical and chemical behavior of CO_2 and CO_2/ H_2O mixtures injected into carbonate sediments under a range of pressures and temperatures, and with a range of sediment compositions.

B.9.4 CO_2 Sequestration in Redbed Sandstones

In another project awarded by NETL in 2004, scientists at the University of Pittsburgh will attempt to store CO_2 with SO_2 in redbed sandstones containing feldspar and iron oxides (NETL, 2004l). This project will incorporate modeling and bench-scale testing and will study geological sequestration of CO_2 using the carbonation process. The researchers will use an electron microscope to evaluate reactions that occur at the molecular and atomic levels, and they will try to determine what happens when CO_2 and the minerals interact. They intend to determine whether iron carbonates will form, whether the porosity of the minerals will change, and whether CO_2 will leak out over a large area after many years of storage.

B.9.5 Enhancing Carbonation in Underground CO_2 Sequestration

Yet another project awarded by NETL in 2004 will study the chemistry and kinetics of carbonation using commonly occurring minerals (e.g., olivine) as the geochemical method for sequestering CO_2 (NETL, 2004l). This project, to be conducted by researchers at the Center for Solid State Science at Arizona State University, will use sonic frequencies to increase the exfoliation and particle cracking of the minerals to enhance CO_2 sequestration. Through modeling and experimental investigations, the scientists will attempt to speed up, control, and tailor the carbonation process. As the result of this research, the scientists intend to discover whether CO_2 can be sequestered permanently underground in this manner.

B.10 TERRESTRIAL SEQUESTRATION

Current projects, some of which are summarized in the following paragraphs, include a large-scale demonstration of reforesting recently mined lands in Kentucky and Virginia and a smaller-scale demonstration integrating terrestrial sequestration with the energy production by employing the use of coal combustion byproducts. These projects are based on fostering partnerships between landowners, biomass and biofuels industry representatives, government agencies, and energy producers.

B.10.1 Enhancement of Terrestrial Carbon Sinks through Reclamation of Abandoned Mine Lands in the Appalachians

Stephen F. Austin State University (SFASU), working with Texas Utilities and Westvaco, is studying the CO_2 sequestration potential resulting from afforestation of abandoned mined lands using Northern red oak (NETL, 2003h). Within the Appalachian coal region, there may be up to 400,000 hectares of abandoned mined lands. These areas contain little or no vegetation, provide little wildlife habitat, and may pollute streams. Reclamation and afforestation of these sites has the potential to sequester large quantities of carbon in terrestrial ecosystems. Utility companies with high CO_2 emissions are interested in mitigating these emissions through the use of carbon credits. In order to establish a carbon credit market and claim carbon credits, utility companies need to partner with landowners who do not currently have forests on their land. Abandoned mined lands in Appalachia can offer excellent sites for such partnerships.

This project will determine how to increase carbon sequestration in forests while increasing forest yields and providing other desirable ecosystem benefits. Growth and yield models will be applied to commercial tree species in order to quantify the maximum amount of carbon that can be stored. Discounted cash-flow analyses will be conducted and the soil expectation value will be calculated to predict the per ton cost of carbon sequestration. A carbon credit market between landowners, utility and coal companies will be investigated, as well as analysis of the impact of sequestration on the local economy.

B.10.2 Enhancing Carbon Sequestration by Matching Amendment Techniques and Land Types

Oak Ridge National Laboratory and Pacific Northwest National Laboratory are leading a project to determine the best way to increase the carbon sequestration potential of land previously disturbed by mining, highway construction, or poor land management practices (NETL, 2003g). The team will focus on the use of amendments derived from paper production, biological waste treatment facilities, and solid byproducts from fossil-fuel combustion to identify and quantify the key factors necessary for the successful reclamation of degraded lands. The results will be summarized in a set of guidelines containing practical information about matching amendment combinations to land types and optimum site-management practices. Long-term field studies will be designed and sites recommended for demonstration and further optimization.

B.10.3 Carbon Capture and Water Emissions Treatment System at Fossil-fueled Electric Generating Plants

The Tennessee Valley Authority (TVA) and Electric Power Research Institute (EPRI) have partnered on an effort to demonstrate and assess the life-cycle costs of integrating electricity production with enhanced terrestrial carbon sequestration (NETL, 2002k). The project is being conducted on coalmine spoil land at the 2,558 MW Paradise Station in Kentucky. This station, which burns bituminous coal and is currently equipped with flue gas desulfurization (FGD) for SO_2 control and is set to begin using selective catalytic reduction for NO_X control, will use the byproducts from these control systems to amend the mine soils. Treated water from the FGD system settling pond discharge will be used to irrigate the soils. Benefits include the use of byproducts to improve reclamation sites and enhance carbon sequestration, the development of a passive technology for the reduction of criteria pollutant release to water, the development of wildlife habitat and green space, the generation of Total Maximum Daily Load (TMDL) credits for water and airborne nitrogen, and the development of additional forestlands. After 2 years the planted trees will have demonstrated greater than 80 percent survival rates and have the potential to sequester carbon at rates up to 6.7 metric tons per hectare per year.

B.10.4 Actively Mined Land Reclamation in Kentucky

The University of Kentucky is leading an effort to study the use of low-compaction reclamation techniques to facilitate reforestation (NETL, 2005a). More than 550 acres of mined land have been planted with high value hardwoods. Each site has been prepared using the FRA by either ripping previously mined sites or loosely compacting new soils that will act as a rooting medium. The research effort will consider the effect of species, spoil type and spoil handling on carbon sequestration. An economic assessment will be completed to determine the cost and potential to reclaim previously mined lands.

B.10.5 Restoring Sustainable Forests on Appalachian Mined Lands in West Virginia and Virginia

Virginia Tech is leading a project to demonstrate terrestrial sequestration for wood products, renewable energy, carbon storage, and other ecosystem services on three 30- to 40-hectare strip mine areas owned by Mead-Westvaco Corporation and Plum Creek Timber Company in West Virginia and Pittston Coal Company in Virginia (NETL, 2003h). The project intends to determine mine soil properties that influence the amount of carbon sequestered. Terrestrial sequestration testing will determine the biological and economic potential of reforesting the sites. Cost-benefit analyses will be done for each management approach. Thus far, a carbon inventory has been made for 14 mined and 7 non-mined forests across an age and site quality gradient. Trees were planted in March 2004 on the study sites and an intensive measurement and monitoring program is underway to estimate the carbon sequestration potential at the sites (NETL, 2003h).

B.10.6 Exploring Terrestrial Sequestration Opportunities in the Southwest United States

The Applied Terrestrial Sequestration Partnership, an integrated research program led by Los Alamos National Laboratory (LANL) and NETL, is taking a leading role in developing breakthrough technologies and applications for terrestrial carbon sequestration (NETL, 2003g). Understanding both ecosystem dynamics and economic issues is critical to the success of terrestrial sequestration as a policy option. Marginal lands (forest, farm, range, or industrial) can serve as a barometer for climate change and are ideal field sites for investigating terrestrial sequestration. The study uses a multidisciplinary approach, integrating lab and field studies with modeling (using CENTURY algorithms). The results will provide a fundamental understanding of how changes in the plant community are reflected in carbon inventories and include a detailed economic analysis of carbon sequestration in reclamation sites.

B.10.7 Development and Application of Appropriate Tools and Technologies for Cost-effective Carbon Sequestration

The Nature Conservancy (TNC) is working in close collaboration with U.S. companies (including General Motors and American Electric Power), foreign governments, and NGO partners to develop a system of project planning tools and measurement technologies that can measure the carbon sequestration benefits on several existing carbon sequestration projects. The project is using new aerial and satellite based technology to study forestry projects in Brazil and Belize to measure the rate of change of carbon in aboveground biomass. Soil carbon technologies and sampling strategies are being developed to estimate the cost of determining the rate of change in soil carbon. Several software models are being applied or developed to determine: optimal land management practices; and locations where carbon benefits will be permanent and provide other benefits such as enhancing biodiversity. In addition, feasibility assessments are being conducted for ecosystems across the U.S. to determine the bio-physical and economic potential for carbon sequestration (NETL, 2003g).

B.11 OCEAN FERTILIZATION

Oceans absorb, release, and store large amounts of CO_2 from the atmosphere through natural processes. Ocean fertilization is one of two approaches for enhancing oceanic carbon sequestration that take advantage of the ocean's natural processes. This approach intends to enhance the productivity of ocean biological systems through fertilization or other means. The other approach, which involves injecting CO_2 into the deep ocean, is described in the next section.

Experimental results and observed surges in phytoplankton growth after dust clouds pass over certain ocean regions indicate that increasing the concentration of iron and other macronutrients in some ocean waters can greatly enhance the growth of phytoplankton and resulting CO_2 uptake. However, ocean fertilization remains highly controversial because of uncertainty surrounding other changes it may cause in complex marine environments (NETL, 2005b). Although there are no current R&D efforts underway for ocean fertilization in the Carbon Sequestration Program, future research in the following areas would be necessary to assess the feasibility of this approach:

- Establishing the scientific knowledge base needed to understand, assess, and optimize ocean fertilization;
- Developing effective macronutrient seeding methodologies; and
- Assessing the long-term fate and flux of CO_2 in marine environments.

B.12 DEEP OCEAN INJECTION OF CO_2

The world's oceans represent the largest potential sink for CO_2 produced by human activities, but the scientific knowledge to support active ocean sequestration is not yet adequate. Oceans already contain the equivalent of an estimated 140 trillion tons of CO_2. Natural carbon transfer processes in oceans span thousands of years and will eventually transfer 80 to 90 percent of today's manmade CO_2 emissions to the deep ocean. This natural CO_2 transfer may already be adversely affecting marine life and may also be altering deep ocean circulation patterns (NETL, 2002l).

Compared to terrestrial and geologic sequestration, the concept of ocean sequestration is in a much earlier stage of development. No commercial-scale applications of deep ocean injection have yet been conducted, although the Program has sponsored small-scale experiments. Research is focused on learning more about the ocean carbon cycle and deep ocean ecosystems, assessing the environmental impacts of CO_2 storage, and understanding the mechanisms by which CO_2 hydrates form. The Program previously funded laboratory experiments aimed at learning more about the basics of CO_2 drop behavior in an ocean environment and the behavior of CO_2 hydrates. NETL has the capability to simulate deep ocean conditions and has been conducting experiments on CO_2 droplet stability. Also, a conceptual design of infrastructure for CO_2 transport and injection has been developed (NETL, 2005b). Examples of current R&D projects are described in the following paragraphs.

B.12.1 Experiments on the Ocean Disposal of Fossil Fuel CO_2

Monterey Bay Aquarium Research Institute (MBARI) is leading a project sponsored by NETL to use a remotely operated vehicle (ROV) to carry out pilot experiments involving the deployment of small quantities of liquid CO_2 in the deep ocean (NETL, 2002l and 2005b). The project will investigate the fundamental science underlying concepts of ocean CO_2 sequestration. Below a depth of about 10,000 feet the density of liquid CO_2 exceeds that of seawater, and the liquid CO_2 is quickly converted into a solid clathrate hydrate by reacting with the surrounding water. Clathrate hydrates are a class of solids in which gas molecules are bound inside cages made up of hydrogen-bonded water molecules.

B.12.2 Optimized In Situ Raman Spectroscopy on the Sea Floor and Effects of Clathrate Hydrates on Sediment

In another project sponsored by NETL, a research group at Washington University in St. Louis will work with MBARI to carry out the first direct in situ analysis on the ocean floor of CO_2 clathrate hydrates, surrounding fluids, and sediments adjacent to the hydrates using a Raman spectrometer (NETL, 2002l). This information on the physical chemistry of clathrate hydrates and sediment interaction is essential for the evaluation of impacts of CO_2 ocean sequestration on the ocean floor ecosystem.

B.12.3 Accelerated Carbonated Dissolution as a CO_2 Capture and Sequestration Strategy

Lawrence Livermore National Laboratory and USGS are conducting laboratory studies to synthesize and investigate the physical properties of CO_2 hydrates and to contrast them with properties of methane hydrates (NETL, 2002l). Additionally, gas-solid exchange experiments will be performed with methane hydrates to determine whether methane extraction and CO_2 sequestration can be accomplished in a single step by replacing methane hydrates with CO_2 hydrates.

A related effort lead by the University of Pittsburgh is directed at determining the fate of CO_2 introduced into the deep ocean and how the icelike CO_2 hydrate impacts the process (NETL, 2002m). The experimental work is carried out in two facilities: a High-pressure, Variable-volume View-Cell (HVVC) and a High-pressure Water Tunnel Facility (HTWF). In addition, a Low-pressure Water Tunnel Facility (LWTF) capable of being chilled has been constructed and used to test various configurations of flow conditioners and section divergence angle and length. Results show that under conditions of temperature and pressure planned for deep-ocean sequestration, the formation of hydrate from dissolved CO_2 may be in areas of elevated dissolved CO_2 concentration, such as near the injection site. The project will provide useful information and models for the development and optimization of CO_2 storage in oceans.

B.12.4 Large Scale CO_2 Transportation and Deep Ocean Sequestration

The objective of a project led by McDermott Technology Inc. and the University of Hawaii is to investigate the technical and economic feasibility of large-scale CO_2 transportation and deep ocean sequestration by focusing on two cases. One case would involve ocean tanker transport of liquid CO_2 to an off-shore floating platform on a barge where it would be injected vertically to the ocean floor. The other case would involve transporting liquid CO_2 through undersea pipelines to the ocean floor (NETL, 2002l).

B.12.5 Collaboration with the International Project on CO_2 Ocean Sequestration

Several efforts sponsored by NETL have supported the International Project on CO_2 Ocean Sequestration (IPCOS), which involves four nations (United States, Japan, Norway, and Canada) and one private corporation (CABB of Switzerland). It includes field experiments at Keahole Point on the Kana Coast off the big island of Hawaii (NETL, 2002l and 2005b). One of NETL's projects has developed instrumentation and potential experiments for the IPCOS. Another NETL project has provided logistical and technical support for the IPCOS, including a surface vessel for the project, biological experiments, and a survey of potential test sites. Another project sponsored by NETL has conducted public outreach and permitting activities associated with the IPCOS. DOE also prepared an EA (NETL, 2001) to analyze the potential environmental impacts of an experiment to test the dissolution and dispersion of liquid carbon dioxide in ocean water at moderate depth, which concluded with the issuance of a FONSI.

B.13 GEOLOGIC SEQUESTRATION MONITORING, MITIGATION AND VERIFICATION (MM&V)

B.13.1 Weyburn Sequestration Project – Geologic Reservoir Mapping and Assessment

In the ongoing Weyburn Sequestration Project for EOR and geologic storage of CO_2 (see Section 3.2.2.2), new reservoir mapping and predictive tools are being used to develop a better understanding of the behavior of CO_2 in a geologic formation (NETL 2004m and 2005b). Key objectives of this research are to study the geological, geophysical and geochemical aspects of the Weyburn field and map the migration and distribution of existing formation fluids (including resident CO_2) as well as injected fluids. The goal of this effort is to measure and study the movement of the injected CO_2 at the Weyburn field and thereby expand the knowledge base of the capacity, transport, fate and storage integrity of CO_2 injected into geologic formations.

What has made the Weyburn oil field a most promising site for research is the Saskatchewan Province's near-complete collection of records and reports on the geophysical, production, and injection activities in CO_2 recycle compressors used in EOR activities at the Weyburn oil field since its discovery. These records are expected to provide a sound basis for developing analytical and monitoring methodologies for future carbon sequestration efforts (Fitzpatrick, 2004). By undertaking such monitoring projects and by demonstrating that the injected CO_2 can be stored effectively over geologic timescales, confidence will be enhanced in geologic storage as a CO_2 mitigation option.

B.13.2 Saline Formation CO_2 Storage (SACS) Project and MM&V Research at Sleipner

In conjunction with the sequestration project at the Sleipner West Gas Field in the Norwegian North Sea (see Section 3.2.2.2), the Saline Aquifer CO_2 Storage (SACS) project was initiated in 1997 to monitor and verify the fate of injected CO_2. The first phase of monitoring was completed in 2000, and researchers confirmed that there was no leakage from the Utsira formation. The spread of CO_2 through the formation is recorded by seismic surveys. SACS researchers are now developing methods and documentation to verify the reliability, environmental acceptability, and safety of CO_2 storage in saline reservoirs.

B.13.3 Sea Floor Gravity Survey of the Sleipner Field to Monitor CO_2 Migration

In a SACS-associated project sponsored by NETL, the Scripps Institute of Oceanography at the University of California, San Diego and Statoil are collaborating on a seafloor gravity survey to monitor CO_2 migration at the Sleipner site (NETL, 2004n). Utilizing high precision gravitational surveying techniques along with seismic data, the primary project goal is to quantify the change in the local gravitational field associated with the sequestration of CO_2 in the Utsira saline reservoir below the bed of the North Sea. This research will determine the effectiveness of using microgravity techniques to monitor and predict the behavior of geologically sequestered CO_2.

B.13.4 GEO-SEQ Project MM&V

The GEO-SEQ Project (see Section 3.2.2.2) has carried out eight separate, but related, tasks that provide new methods and approaches for reducing the cost and risk of geologic sequestration (NETL, 2004j). The results from these tasks will provide the basis for the development of a set of best practices for MM&V of geologic sequestration. The benefits of this project are anticipated to include lower sequestration costs, lower sequestration risk, decreased implementation time, and increased public acceptance. The eight tasks included in this project are:

- Co-optimization of carbon sequestration with oil and gas recovery
- Carbon sequestration with enhanced gas recovery
- Co-disposal of CO_2, H_2S, NO_X, and SO_2
- Evaluation of geophysical monitoring technologies
- Application of natural and introduced tracers
- Enhancement of numerical simulators for GHG sequestration in deep unminable coal seams and in oil, gas, and brine formations
- Improving the methodology for capacity assessment
- Frio pilot test.

As a component of the GEO-SEQ Project, the research team is seeking to provide methods that utilize the power of natural and introduced tracers to decipher the fate and transport of CO_2 injected into the subsurface. The team is investigating the effectiveness of tracers of stable isotopes (oxygen, sulfur, carbon, nitrogen), noble gas isotopes, and radioactive isotopes. The resulting data will be used to calibrate and validate predictive models used for: (1) estimating CO_2 residence time, reservoir storage capacity, and storage mechanisms; (2) testing injection scenarios for process optimization; and (3) assessing the potential leakage of CO_2 from the reservoir (NETL, 2005b).

B.13.5 Natural Analogs for Geologic CO_2 Sequestration (NACS)

Brookhaven National Laboratory is collaborating with LANL and other institutions on a MM&V project sponsored by NETL at the West Pearl Queen Oil Field (see Section 3.2.2.2) in New Mexico. The primary objective is to evaluate a wide range of surface and near-surface monitoring techniques that show promise in the detection of both the short term, rapid loss, and long-term, intermittent slow leakage of CO_2 from geologic formations (NETL, 2002n). The researchers are monitoring for CO_2 leakage at the West Pearl Queen site to determine the migration and fate of CO_2 after being injected into a depleted oil reservoir. Models and data developed will be used to predict physical and chemical changes in oil reservoir properties and the long-term storage capacity, safety, and integrity of oil reservoir sequestration.

The researchers have conducted background studies of geologic features, soil and atmosphere hydrocarbon patterns and concentrations, and selected monitoring locations and grid patterns for soil-gas sampling. They are using perfluorocarbon tracer compounds and evaluating tracer retention on coal. They are also performing geophysical site analysis from remote sensing and ground-based measurements by combining satellite visible and infrared views with satellite radar and optical aerial photography.

Natural Analogs for Geologic CO_2 Sequestration (NACS)

Advanced Resources International is leading a study sponsored by NETL to document the capability of depleted oil and gas fields to sequester CO_2 safely and securely (NETL, 2003i). The study will also investigate long-term reactions between CO_2 and the various minerals in the reservoir and cap rocks.

At present, five large natural CO_2 reservoirs in the United States provide a total of 25 million tons of CO_2 that is injected into oil fields for EOR. The NACS project is performing a multi-disciplinary geologic engineering study of three of these reservoirs (Kinder Morgan's McElmo field in Colorado, Ridgeway's St. Johns Dome in Arizona and New Mexico, and Denbury Resources' Jackson Dome field in Mississippi), with the objective of comparing the capabilities of naturally occurring CO_2 reservoirs with the capabilities of depleted oil and gas fields to sequester CO_2 securely and economically.

B.13.6 Depleted Oil Reservoir Migration

As a component of the West Pearl Queen Field sequestration project (see Section 3.2.2.2), the research team is using a comprehensive suite of computer simulations, laboratory tests, and field measurements to understand, predict, and monitor the geochemical and hydrogeologic processes involved during CO_2 sequestration in a depleted sandstone oil reservoir (NETL, 2003e). The project includes geologic flow/reaction modeling; geophysical monitoring of the advancing CO_2 plume; and laboratory experiments to measure reservoir changes due to CO_2 flooding. The models and data are being used to predict storage capacity as well as physical and chemical changes in reservoir properties, such as fluid composition, porosity, permeability, and phase relations.

B.13.7 Digital Spatial Database to Catalogue Geologic Sequestration Sites in the Midwest

The Mid-continent Interactive Digital Carbon Atlas and Relational Database (MIDCARB) is a joint project between the State Geological Surveys of Illinois, Indiana, Kansas, Kentucky, and Ohio, sponsored by NETL (NETL, 2003j). The purpose of MIDCARB is to enable the evaluation of carbon sequestration potential in the sponsoring states. When completed, the digital spatial database will allow users to estimate the amount of CO_2 emitted by sources (such as power plants, refineries and other fossil fuel consuming industries) in relation to geologic reservoirs that can provide safe, secure sequestration sites over long periods of time. MIDCARB is organizing and enhancing the critical information about CO_2 sources and developing the technology needed to access, query, model, analyze, display, and distribute natural-resource data related to carbon management.

B.13.8 Development of a Carbon Management Geographic Information System for the United States

The Massachusetts Institute of Technology (MIT) is leading a study sponsored by NETL to develop a systems analysis tool that will aid in the development and deployment of carbon capture and sequestration technologies in the U.S. (NETL, 2005b). This project will take a top-down approach to potential CO_2

sequestration storage sites and complement the MIDCARB project, which is using a bottoms-up approach in five Midwest states.

B.14 TERRESTRIAL SEQUESTRATION MM&V

B.14.1 Appropriate Tools and Technologies for Cost-effective Terrestrial Sequestration

Through the ongoing development and implementation of carbon sequestration projects on a demonstration scale, TNC is participating in a cooperative agreement with NETL to explore the compatibility of carbon sequestration in terrestrial ecosystems with the conservation of biodiversity (NETL, 2003k). TNC's first involvement in assessing this approach occurred in 1994 with the development of the Rio Bravo Carbon Sequestration Pilot Project in Belize. Since then, TNC has initiated several other projects with a variety of partners.

The collaborative effort with NETL is focused on gaining cost-effective, verifiable measurements of the long-term potential of various terrestrial carbon sequestration strategies and assessing land use practices that avoid emissions of CO_2. The project will use newly developed aerial and satellite-based technology to study forestry projects in Brazil and Belize to determine their potential for carbon sequestration, and it will also test new software models to predict how soil and vegetation store carbon at sites in the U.S. and abroad. The following are accomplishments to date:

- Advanced videography has been applied to pine savannah analysis in Belize.
- Feasibility studies on several different U.S. ecosystems have been initiated to determine which ecosystem types offer viable options for carbon sequestration.
- The GEOMOD spatial analysis tool has been used to determine and validate baseline analyses.
- An alternative baseline method developed by TNC (the Euclidean Distance between Agriculture and Forest (EDAF) method) has been further refined in baseline analyses in Brazil.
- A technical advisory panel was organized to address the issues associated with baseline and leakage estimates.
- Soil monitoring is being conducted using laser-induced breakdown spectroscopy (LIBS), which is being developed by the Los Alamos National Laboratory.

B.14.2 Next-Generation Soil Carbon Measurement

The LANL and USDA are collaborating on the development of an advanced Laser-Induced Breakdown Spectroscopy (LIBS) device for field-based detection of soil carbon. The goal is a LIBS device that will enable researchers to obtain accurate measurements of soil carbon in several seconds (NETL, 2005b).

B.14.3 Genetic Diversity Analyses as an Indicator of Soil Carbon Accumulation

The LANL is leading an effort to develop a better understanding of plant growth and relationships between carbon storage, soil microbes, and water and nutrient utilization. Studies are directed at advanced plant growth, soil microbes and carbon/water interactions to enhance vegetation growth to maximize carbon storage, evaluating carbon transfer from plant to soil, and assessing and improving land management practices to increase net carbon storage (NETL, 2005b).

B.14.4 Ocean Sequestration MM&V

Established protocols for measuring dissolved organic and inorganic carbon in ocean waters have been developed as a part of varied studies of ocean ecosystems. Additional research is needed to provide a capability to visualize hydrate formation, as well as to develop advanced tools (e.g., diffraction, nuclear magnetic resonance spectroscopy, and Raman spectroscopy) for monitoring seawater chemistry and biological impacts in situ (NETL, 2005b).

B.15 BREAKTHROUGH CONCEPTS

An alternative to sequestering CO_2 as a gas, liquid, or solid is to convert it into another chemical compound. Many CO_2 conversion processes are found in nature, the most common of which is photosynthesis. Additionally, mollusks and crustaceans use CO_2 that is dissolved in ocean water to build their carbonate-based shells. Sandstone also reacts with CO_2 in the air to form minerals. Further evidence suggests that CO_2 trapped in geologic formations over eons has been converted to methane, carbonates, and other compounds though biochemical processes (NETL, 2005b).

The Carbon Sequestration Program seeks to mimic naturally occurring processes when developing breakthrough CO_2 conversion methods. This is a challenging task, because CO_2 is a highly stable compound containing a very low amount of chemical energy, and the natural conversion processes are slow and inefficient as a consequence. The Program is performing applied research to complement the efforts of organizations conducting basic scientific research in this field, including research by the DOE Office of Science and the National Science Foundation.

The CO_2 conversion processes can reduce net carbon emissions and provide significant secondary benefits such as the following:

- Photosynthesis and other biochemical processes convert CO_2 into fuel (biomass), creating regenerable energy systems that can displace new fossil resource use.
- Certain biochemical processes use CO_2 to produce pharmaceutical compounds or specialty chemicals that can be recovered and used to offset the cost of CO_2 capture.
- Mineralization converts CO_2 into carbonate rocks, which can be used for soil supplements, construction fill, and other applications.

The Program is collaborating with the National Academies of Science (NAS) to expand the number of projects from industry and academia. The Program is also funding facilities and experiments at the Carbon Sequestration Science Focus Area (CSSFA), which uses in-house resources at NETL to conduct research in a number of sequestration areas with a focus on high technical risk concepts (NETL, 2004b). Examples of R&D efforts are summarized in the following paragraphs.

B.15.1 CO_2 Mineralization

Mineral carbonation, alternately referred to as mineral sequestration, is the reaction of CO_2 with non-carbonate minerals, such as olivine and serpentine, to form geologically stable mineral carbonates. Mineral carbonation can be achieved via two methods. In the first case, minerals can be mixed and reacted with CO_2 in a process plant to produce inert carbonates. In the second, CO_2 can be injected into selected underground mineral deposits, similar to geological sequestration, but resulting in carbonation (NETL, 2000).

- Using mineral carbonation to reduce CO_2 emissions has potential advantages, including:
- Long-term stability of carbonates

- Natural abundance of suitable compounds for binding CO_2
- Economic feasibility of the conversion process

However, mineral carbonation processes will be practical only when two key issues are resolved. First, a fast reaction route must be found that optimizes energy management. Second, issues need to be quantified and addressed pertaining to the mining and processing activities required for mineral sequestration, especially concerns related to overall economics and environmental impacts.

The Mineral Carbonation Program is being managed through NETL's Environmental Product Division and is supported by the Coal Utilization Science, University Coal Research, and the Advanced Metallurgical Processes programs (NETL, 2000). The primary goal of the study is to generate a useful knowledge base that can lead to development of mineral CO_2 sequestration methods. To achieve this goal, the reaction mechanisms, heat requirements, and environmental interactions must be understood well enough to permit the development of engineering processes. A secondary goal is to acquire knowledge essential to understanding the reactions of CO_2 with underground minerals in support of DOE's geological sequestration programs, where CO_2 may be injected into deep saline formations or depleted oil or gas reservoirs. Knowledge of the reaction characteristics of CO_2 with various minerals at elevated pressures and temperatures, such as those found deep underground, will help scientists predict the long-term effects of such practices.

Progress to date has been extremely encouraging. Research has found that finely ground serpentine ($Mg_3Si_2O_5(OH)_4$) or olivine (Mg_2SiO_4) will react with CO_2 in solutions of supercritical CO_2 and water to form magnesium carbonate ($MgCO_3$). When the effort first started, it required 24 hours to produce a 50 percent carbonation level using an olivine feedstock at reaction temperatures of 150-250°C and pressures of 85-100 bar. Through careful control of solution chemistry, the process has been accelerated so that 84 percent conversion of olivine can be achieved in just 6 hours. Furthermore, when heat pretreated serpentine is reacted using the same enhanced reaction process, approximately 80 percent conversion occurs in less than an hour. Carbonation studies are continuing with highly instrumented reactors and atomic-level simulations to optimize reaction conditions and explore the use of catalysts and alternative feedstocks.

B.15.2 Process Design for the Biocatalysis of Value-Added Chemicals from Carbon Dioxide

Researchers from the University of Georgia Research Foundation will conduct a novel project awarded by NETL in early 2004 (NETL, 2004l). They will perform metabolic engineering to create strains of microbes that absorb CO_2 and produce byproducts such as succinic, malic, and fumeric acids, all of which have commercial value. The advantage of the proposed process is that microbial strains will be placed in direct contact with the gases emitted from power plants, thereby avoiding the cost of commercial CO_2 capture systems.

B.15.3 Capture and Sequestration of CO_2 from Stationary Combustion Systems by Photosynthesis of Microalgae

A team led by Physical Sciences, Inc. is performing a project to characterize types of flue gas and determine which separation and cleanup technologies are necessary to maximize the conversion of CO_2 by microalgae photosynthesis (NETL, 2004o). Certain species of microalgae that can withstand the harsh conditions associated with flue gas have optimal rates of carbon fixation and have the ability to convert CO_2 into inorganic carbonates. The primary project goal is to develop technologies pertaining to: (1) the treatment of effluent gases from fossil fuel combustion systems; (2) the transfer of CO_2 into aquatic media; and (3) the efficient conversion of CO_2 by photosynthetic reactions to materials for reuse or sequestration. The objectives of this project are to design an industrial-scale sequestration system for combustion units and model the sequestration process to perform an economic analysis and provide cost-effective solutions.

By early 2004, the project had tested 50 strains of microalgae for growth at different temperatures; analyzed 34 strains for high-value pigments; tested 21 strains for tolerances to simulated flue gases; and tested 28 strains for potential carbon sequestration into carbonates for long-term storage. The researchers also tested a CO_2 removal process, a CO_2 injection device, process control devices, and an algae separation process for a scaled-up photo-bioreactor.

B.15.4 Enhanced Practical Photosynthetic CO_2 Mitigation

Ohio University, Montana State University, and Oak Ridge National Laboratory are performing a NETL-sponsored project to demonstrate the technical and economic feasibility of an enhanced photosynthetic system that takes up CO_2 from flue gases at power plants (NETL, 2004p). The desired systems will separate sunlight into spectral regions to maximize the growth of photosynthetic cyanobacteria. The goal is to have a self-powering system that can reduce CO_2 emissions onsite in a relatively compact space.

Besides mitigating CO_2 emissions, this novel method of photosynthetic sequestration could provide three other benefits. First, it would generate oxygen, which is a natural product of photosynthesis. Second, it would reduce gaseous pollutants, because the flow process used to enhance the soluble carbon concentration is a natural scrubber. The NO_X would be converted to nitrates, SO_x would be converted to sulfates and sulfites, and any NH_3 that might slip through an upstream Selective Catalytic Reduction (SCR) process for NO_X reduction would be scrubbed as well. Such scrubbing is beneficial to photosynthesis, because the microalgae require nitrogen to grow. Third, it would produce biomass for beneficial end-uses; microalgae have been used as soil stabilizers and fertilizers, in the generation of biofuels (biodiesel and ethanol), and in the production of hydrogen for fuel cells. Microalgal biomass has also shown suitable ignition characteristics for co-firing in pulverized coal-fired generation units.

Other NETL-sponsored studies are also investigating natural processes in algae and bacteria for use in innovative carbon sequestration (NETL, 2005b):

- The INEEL is studying the use of cyanobacteria as a biofilm with the aim of optimizing its physiology for efficient photosynthesis and CO_2 saturation.
- The University of North Dakota Energy and Environmental Research Center is evaluating the use of microalgae for onsite removal of CO_2 from flue gas.
- California State University San Marcos is performing a study of potential carbon sequestration through the conversion of CO_2 to calcium carbonate by coccolithophorid algae.

B.16 NON-CO_2 GREENHOUSE GAS MITIGATION

Non-CO_2 emissions from human-related activities contribute approximately 20 percent of the manmade greenhouse effect. Since many non-CO_2 GHG have significant economic value, their emissions can often be avoided or captured at a low net cost.

Methane (CH_4), nitrous oxide (N_2O), chlorofluorocarbons (CFCs), sulfur hexafluoride (SF_6), ozone (O_3), and other gases have different measures of effectiveness at absorbing infrared (heat) radiation from the earth and holding it in the atmosphere, which is called the global warming potential (GWP). Table C-

1 shows the major GHG, their historic and current atmospheric concentrations, and their GWP values over a 100-year time horizon relative to CO_2.

Table C-1. Comparison of Greenhouse Gases

Gas	Pre-1750 Tropospheric Concentration	Current Tropospheric Concentration	GWP 100-yr	Lifetime in Atmosphere (years)
Carbon Dioxide	280 ppm	370 ppm	1	Variable
Methane	709 ppb	1,786 ppb	23	12
Nitrous Oxide	270 ppb	315 ppb	296	114
CFCs (-11, -12, -113)	0	885 ppt	4,600 – 10,600	45 – 100
Others	0	311ppt	140 – 22,200	<5 – 10,000

ppm – part per million , ppb – parts per billion , ppt – parts per trillion

GWP – global warming potential, relative to CO_2 GWP of 1.0.

(Source: NETL, 2005b)

The Carbon Sequestration Program focuses on areas in which non-CO_2 GHG abatement is integrated with energy production, conversion, and use. The Program also works with the EPA Methane and Sequestration Program to assess the role of non-CO_2 GHG emissions abatement actions in a nationwide strategy for reducing GHG emissions intensity, and to identify priority areas for research and development (NETL, 2005b). Examples of R&D efforts are summarized in the following paragraphs.

- The Yolo County (California) Department of Planning and Public Works is constructing a full-scale bioreactor landfill as a part of the EPA's Project XL program to develop innovative waste management approaches while providing superior GHG emissions protection (NETL, 2003l). NETL is a co-sponsor for the project.
- In a bioreactor landfill, controlled quantities of liquid (leachate, groundwater, grey-water, etc.) are added and recirculated as necessary to maintain the waste at or near its moisture holding capacity. This process significantly increases the biodegradation rate of the waste and thus decreases the waste stabilization and decomposing time (5 to 10 years) relative to what would occur within a conventional landfill (30 to 50 years or more). If the waste decomposes anaerobically (in the absence of oxygen), it produces landfill gas that is primarily methane, a GHG. Methane is over 20 times more potent than CO_2 in its effects on the atmosphere. This byproduct of anaerobic landfill waste decomposition can be a substantial renewable energy resource that can be recovered for power generation or other uses.
- In the initial phase of this project, a 12-acre landfill module was constructed consisting of several cells. The cells include instrumentation to monitor bioreactor performance. The final phase, pertaining to carbon sequestration, involves evaluating full-scale performance and potential of aerobic and anaerobic bioreactor landfill cells as tools for abating GHG emissions resulting from organic waste decomposition in landfills.

B.16.1 Mine-mouth Ventilation Methane Mitigation

Consol Energy, Inc. and MEGTEC Systems are performing a project co-funded by EPA and NETL to design, build, and operate for 12 months a commercial-scale thermal flow reversal reactor (TFRR) interfaced with a working coal mine ventilation fan to reduce emissions of methane (NETL, 2004q). The TFRR technology employs the principle of regenerative heat exchange between a gas and a solid bed of a heat exchange medium. Ventilation air methane flows into and through the reactor in one direction, and the temperature is increased until the methane is oxidized. The hot products of oxidation then lose heat as they continue toward the far side of the bed. At a specified interval, the flow is automatically reversed, so that the hot part of the bed heats the incoming gas. Through the use of heat exchange, excess heat may be transferred for local heating needs or for the production of electric power. The TFRR will oxidize 95 percent of the methane in the vent stream to CO_2, thereby reducing its global warming potential by 87 percent.

B.16.2 Coal Mine Waste Methane Utilization

DOE prepared a draft Environmental Assessment to evaluate potential impacts from the construction and operation of an Integrated Power Generation System for Coal Mine Waste Methane Utilization (NETL, 2002p). DOE's objective for participating in a cooperative agreement with Northwest Fuel Development, Inc. was to support the demonstration of a technology having the potential to reduce methane emissions from coal mines. Specifically, DOE intended to provide partial funding (approximately 35 percent of the total project cost) to demonstrate the application of a system which would collect "gob gas" (waste methane from the mined out portion of an underground mine following extraction of the coal using long-wall mining), upgrade the gas by removing impurities (primarily water, carbon dioxide, and nitrogen), and use the fuel gas in a series of 18 modular reciprocating internal combustion engines driving electrical generators to produce electricity for use at the mine. A portion of the gas meeting pipeline quality standards would be sold to the local gas distribution company.

B.16.3 Upgrading Methane Streams with Ultra-fast Thermal Swing Adsorption (TSA)

The separation of nitrogen from methane is one of the most significant challenges in recovering low-purity methane streams. In a project sponsored by NETL, Velocys, Inc. will focus on the separation of nitrogen from methane by applying a proprietary modular microchannel process technology (MPT) to achieve ultra-fast thermal swing adsorption (TSA). The primary goal of this project is to design and demonstrate a revolutionary approach for upgrading low-BTU methane streams from coalmines, landfills, and other sources (NETL, 2004r). MPT employs small process channels to greatly enhance heat and mass transfer. Enhanced heat transfer yields TSA cycle times of seconds compared to hours for conventional TSA systems and enables compact, economic systems for upgrading methane streams to pipeline quality.

The project is being conducted in two phases. The objective of the first phase is to assess the technical and market feasibility of an MPT-based TSA approach for upgrading low-BTU methane streams. The objective of the second phase is to conduct bench-scale demonstration of Ultra-fast TSA. Thus far, preliminary tests have been initiated and include the collection of methane and nitrogen capacity over several temperatures, compositions, and pressures.

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APPENDIX C. MEASURES TO MITIGATE UNAVOIDABLE ADVERSE IMPACTS

Chapter 4 identified potential adverse impacts of program technologies along with mitigation measures and BMPs that could be implemented to either avoid or minimize these effects. A summary of unavoidable adverse impacts to each resource and methods to mitigate their effects are discussed herein.

C.1 ATMOSPHERIC RESOURCES

- Operation of trucks, compressor engines, pumps, and heating units to convey and inject CO_2 into geologic formations would release both criteria pollutants and CO_2. Emissions from compressors, pumps, and heaters could be mitigated by using BACTs or by connecting them to electric utilities whenever feasible.
- Locate CO_2 pipelines and injection areas away from populated areas and environmentally sensitive areas.
- Localized generation of fugitive dust and particulate emissions would result from land clearing and construction activities. These emissions can be minimized through BMPs discussed in Section 4.2.
- Accidental releases of H_2S from co-sequestration projects could cause localized releases of toxic air pollutants and result in objectionable odors. Accidental releases of H_2S could be avoided or minimized through inspection and monitoring of system components.

C.2 GEOLOGIC RESOURCES

- The addition of CO_2 to the water-bearing oil reservoir rocks can decrease the water pH and alter the Eh of the formation water, which may mobilize trace elements (e.g., arsenic, selenium, lead), depending on the site-specific geochemical factors. Careful site selection, detailed hydrogeologic characterization, proper construction and operation of facilities, and implementation of BMPs would help preserve both the quality and quantity of groundwater in the area of the sequestration process.
- For co-sequestration projects, H_2S is a strong corrosive agent and could likely cause an increased risk of well casing leaks. In the event of casing leakage into a shallow potable aquifer, the H_2S may cause the groundwater to become more acidic and thus have the potential to mobilize higher concentrations of trace metals in the aquifer. Careful site selection, detailed hydrogeologic characterization, proper planning, and implementation of BMPs would help avoid or mitigate potential impacts to the geologic resources of an area due to the sequestration process.
- Long-term adverse impacts could result from the inadvertent leakage of CO_2, H_2S, other formation fluids, and/or metals into overlying potable water aquifers.

C.3 SURFACE WATER RESOURCES

- Land disturbance during construction activities could result in sedimentation of water bodies due to storm water runoff. These construction activities would comply with state or local soil conservation permit requirements and best management practices to reduce sedimentation of nearby water bodies.
- CBM recovery or EOR may produce a large quantity of process water with elevated dissolved solids and high salinity. Discharge of poor quality water to surface water supplies would cause degradation of the receiving body of surface water. To avoid such impacts, process water that

exceeds CWA standards or local surface water regulations would be treated to meet such standards, or reinjected into permitted UIC wells (deep saline aquifers) where available.

C.4 BIOLOGICAL RESOURCES

- Construction of a CO_2 pipelines could result in localized, temporary destruction of habitat. Standard construction techniques and BMPs would be used to minimize impacts to biological resources. Pipelines would be sited to avoid wetlands and other environmentally sensitive areas, and minimize crossing of streams. Existing rights-of-way would be used whenever possible.
- Construction and operation of surface facilities and pipelines would have the potential for adversely impacting biota in streams and wetlands. The potential impacts could be minimized by proper siting of facilities, and avoiding wetlands and streams. If wetlands and streams could not be avoided, the implementation of BMPs would help minimize adverse impacts.
- If the project was developed in the vicinity of surface water resources or wetlands, there would be a potential for adverse impacts on these resources. The adverse impacts could include impaired water quality caused by increased erosion and runoff from the site that introduces contaminants to the water body or wetland. The implementation of BMPs would help minimize adverse impacts.
- Wetlands and aquatic resources could be affected by site maintenance activities that involve mowing or cutting of wetland and riparian vegetation. The loss of vegetation could result in decreased water quality due to increased surface runoff from the site. The implementation of BMPs would help minimize adverse impacts.

C.5 CULTURAL RESOURCES

- New easements or rights-of-way may be necessary for construction of pipelines, resulting in potential impacts to archaeological and/or American Indian resources. Where practicable, impacts on these resources would be minimized by co-utilizing easements of other utility pipelines and power transmission lines.
- Construction of surface facilities, access roads, and pipelines would have the potential to cause minor adverse impacts to archaeological and Native American resources. This potential is greater if facilities must be sited near surface water features. Compliance with the applicable regulations and requirements would limit the likelihood of construction occurring in or impacting cultural resources.

C.6 AESTHETIC AND SCENIC RESOURCES

- Clearing ROWs during construction and maintenance of ROWs and surface facilities could result in minor or moderate adverse impacts on aesthetic and scenic resources, depending upon the existing characteristics of the proposed corridor.
- Construction activities, including clearing the site and exhaust emissions, fugitive dust, and noise from construction equipment could result in minor short-term adverse impacts to aesthetic and scenic resources.
- Long-term aesthetic impacts from operations would be negligible to minor and could be minimized by siting surface facilities away from important scenic and natural areas.

C.7 LAND USE

- The potential need for easements and rights-of-way for underground CO_2 pipelines and access roads would potentially cause adverse impacts to the existing land use. Where practicable, impacts on land use can be minimized by utilizing easements already established for other utility pipelines and power transmission lines.

- The relatively small site footprints required for surface facilities associated with a coal seam, EOR, or saline aquifer sequestration project have a potential to cause minor impacts on land uses. Aboveground uses in the majority of lands needed for sequestration projects generally would not be altered. Potential impacts to land use would be minimized by avoiding areas of restricted land use when siting the surface facilities.

C.8 MATERIALS AND WASTE MANAGEMENT

- Chemical processes for capturing CO_2 would result in the generation of hazardous waste. Impacts associated with waste disposal would be minimized by disposing of wastes at approved, permitted facilities in accordance with all applicable laws and regulations.
- Co-sequestration technologies would result in additional disposal options for H_2S from power generation, industrial, and mineral extraction processes. Impacts associated with geologic sequestration of H_2S would be minimized through the permitting process.

C.9 HUMAN HEALTH AND SAFETY

- The program would require construction and operational jobs that may result in additional worker injuries. These injuries could be avoided or minimized through proper planning, job training, and daily safety protocols.

C.10 SOCIOECONOMICS AND ENVIRONMENTAL JUSTICE

- Minor adverse impacts to socioeconomics would occur if the program required new facilities or a significant expansion of the existing facility property or would otherwise introduce features (increased air emissions, noise, hazardous materials, etc.) that would adversely affect adjacent housing, businesses, and/or community services. Avoiding locations that may cause displacement of population, residential housing, or local businesses would minimize these potential impacts. Locations that may adversely affect the range and capacity of community services (fire, emergency response, law enforcement, etc.) may also be avoided.

APPENDIX D. CUMULATIVE IMPACTS

The term, cumulative impacts, is defined as impacts to the environment that can potentially result from the combined impact of the action when added to other past, present and reasonably foreseeable future actions regardless of which agency or person undertakes such other actions. Thus, cumulative impacts in the context of this document include:

1) Impacts inclusive of ongoing or planned carbon sequestration activities that may occur beyond the direct and indirect impacts expected from the DOE's Carbon Sequestration Program (i.e.; activities not sponsored or supported by the DOE). Direct and indirect impacts expected from sequestration technologies have been addressed in Chapters 4 and Appendix C of this document, and they form the baseline for consideration of cumulative impacts described in this chapter.
2) Impacts of the Carbon Sequestration Program in context of other Federal and State GHG reduction initiatives.
3) Impacts of the Carbon Sequestration Program in context of international GHG reduction initiatives and treaties.

Since 2001, when President Bush announced the GCCI, the DOE and other federal agencies have been, and will continue to, develop programs to devise accounting rules for carbon sequestration projects, provide frameworks for research and development, and provide incentives to land owners or companies that undertake sequestration projects. Other federal agencies that support carbon sequestration activities include USDA, OSMRE, and NOAA.

In addition to programs instituted solely by the U.S. are several international programs that include the participation of other countries as well as the U.S. through the Carbon Sequestration Leadership Forum (CSLF) and through other means.

The following sections provide brief descriptions of non-DOE sponsored U.S. federal, regional, and private sector greenhouse gas reduction and carbon sequestration initiatives as well as international programs, of which some include U.S. participation.

In addition, the predicted amounts of GHG reductions attributable to other DOE and federal programs and policies (as described in the 2002 US Climate Action Report) are included in the discussion of cumulative impacts. The predicted CO_2 emission reductions fostered by these programs are helpful in understanding the potential contribution of sequestration in meeting the GCCI goal.

Also, the United Nations Framework Convention on Climate Change (UNFCCC) has instituted the Kyoto Protocol, which the U.S. has not ratified. Ratification of Kyoto by a country essentially is a commitment to either reduce their emissions of carbon dioxide and other greenhouse gases and/or participate in an international emissions trading market (Wikipedia, 2006).

D.1 U.S. CARBON SEQUESTRATION ACTIVITIES

D.1.1 Federally Sponsored Domestic Carbon Sequestration Programs

D.1.1.1 FutureGen

FutureGen will be the world's first zero emissions power plant that will produce electricity and hydrogen from coal, while capturing and storing CO_2. FutureGen will initiate operations around 2012. The plant will be designed to generate nominally 275 MW of electricity (roughly equivalent to an average mid-size coal-fired power plant). FutureGen is a public-private partnership, partially sponsored by DOE. One of the requirements of the project is to generate and sequester at least 1 MMT of CO_2 a year. Once captured, the carbon dioxide would be injected deep underground, into a deep saline formation.

D.1.1.2 USDA Carbon Sequestration Programs

The USDA provides incentives, through financial grants, technical assistance, and pilot programs to private landowners, including farmers and forest and grazing landowners for implementing practices that reduce GHGs and store carbon. Among their major programs are the Environmental Quality Incentives Program, the Forest Land Enhancement Program, Conservation Reserve Enhancement Program, Greenhouse Gas Pilot Projects and the Greenhouse Gas Accounting Protocols.

When President Bush announced his Climate Change Strategy, he challenged USDA to recommend targeted incentives for greenhouse gas offsets from agriculture and forests. The 2002 farm bill provided USDA with the authority and a record level of resources to build partnerships including partnerships that target GHGs. The 2002 farm bill included an increase of more than $17 billion for conservation, which opens up many more options for many more producers. In 2003, USDA announced a series of actions it would take to increase carbon sequestration and reduce GHG emissions from forests and agriculture. Coupled with the increases in overall conservation spending, these actions are expected to increase the carbon sequestration and greenhouse gas emissions reductions from the conservation programs by over 12 MMTCE in 2012 (see Table D-1). That reduction represents approximately 12 percent of President Bush's goal to reduce GHG intensity of the American economy by 18 percent in the next decade (USDA, 2004).

Table D-1. Estimated GHG Reductions from USDA Targeted Incentives

USDA Action	Estimated GHG Emission Reduction in 2012 (MMTCE)
Revise the Environmental Quality Incentives Program Ranking Criteria to include GHG emission reductions	7.1
On-farm energy generation and GHG reduction from livestock waste management	2.3
Improved nitrogen application practices in agricultural cropping systems	1
GHG management pilot projects	0.5
Forest Land Enhancement Program (FLEP)	0.4
Revise the Conservation Reserve Program Environmental Benefits Index to include carbon sequestration	0.1
Include 500,000 acres of hardwoods in the Conservation Reserve Program	1.0
Total	12.4

Source: USDA, 2003.

Terrestrial sequestration projects promoted under both the USDA and DOE programs would result in net positive impacts to the environment. These land management projects would: 1) sequester carbon; 2) stabilize soils and reduce erosion; 3) decrease fugitive dust emissions; 4) reduce surface water runoff; 5) improve surface and groundwater quality; and 6) create or preserve open space.

D.1.1.3 OSMRE Reforestation Programs

The DOI Office of Surface Mining's Abandoned Mine Lands program provides for the restoration of eligible lands and water mined and abandoned or left inadequately restored. By reforesting abandoned mine lands, the program supports the goals of terrestrial carbon sequestration. There are no published projections on the amount of carbon that would be sequestered by the program.

OSMRE's program of restoring formerly mined lands would result in similar net positive impacts as other terrestrial sequestration projects fostered under both the USDA's and DOE's program.

D.1.1.4 NOAA Carbon Cycle Programs

NOAA has a number of programs focused on investigating the ocean carbon cycle. Their key programs include the Atlantic Oceanographic and Meteorological Laboratory Carbon Dioxide Program, the Pacific Marine Environmental Laboratory Carbon Dioxide Program, and the Global Carbon Cycle Program. NOAA programs focus on research and development to support the carbon sequestration program by assessing the degree and extent of global climate change, determining the ocean's possible role in climate change and the carbon cycle, and developing new monitoring systems.

NOAA's program is not expected to undertake projects that will directly sequester carbon. However, the pure research programs that they support should facilitate advances that make other sequestration programs more efficient and effective, thus, the aforementioned NOAA programs would have net positive impacts to the environment.

D.1.2 Sequestration Projects Sponsored by the Private Sector in the U.S.

D.1.2.1 Enhanced Oil Recovery

Chevron's Rangely Weber Field in Colorado is one of the largest geologic sequestration sites for anthropogenic CO_2. As of 2003, the project injected 2.6 tons/day of CO_2, purchased from a natural gas processing facility in Wyoming. By the time the project is completed, an estimated total of 25MT of CO_2 will be sequestered.

In 2003, over 8 million tons of CO_2 were used for EOR. However, only 10 percent came from anthropogenic sources. The rest was extracted from naturally occurring deposits. It is estimated that up to three-quarters of the CO_2 injected stays sequestered, although further research and development in this area is expected to improve the storage rate to close to 100 percent (NETL, 2003). Subsequently, it is important to note that commercial EOR projects may not be substantively contributing to the reduction of anthropogenic CO_2 in the atmosphere.

D.2 FEDERAL AND STATE GHG REDUCTION PROGRAMS

D.2.1 Federal GHG Reduction or Avoidance Programs

Since the 1990's, the U.S. has made significant progress in reducing greenhouse gas emissions. The government is pursuing the following broad range of strategies to reduce net emissions of GHGs (US Department of State, 2002):

- **Electricity**: Federal programs promote GHG reductions through the development of cleaner, more efficient technologies for electricity generation and transmission. The government also supports the development of renewable resources, such as solar energy, wind power, geothermal energy, hydropower, bioenergy, and hydrogen fuels.
- **Transportation**: Federal programs promote development of fuel-efficient motor vehicles and trucks, research and development options for producing cleaner fuels, and implementation of programs to reduce the number of vehicle miles traveled.
- **Industry**: Federal programs implement partnership programs with industry to reduce emissions of CO_2 and other GHGs, promote source reduction and recycling, and increase the use of combined heat and power.
- **Buildings**: Federal voluntary programs promote energy efficiency in the nation's commercial, residential, and government buildings by offering technical assistance as well as labeling of efficient products, new homes, and office buildings.

- **Agriculture and Forestry**: The U.S. government implements conservation programs that have the benefit of reducing agricultural emissions, sequestering carbon in soils, and offsetting overall GHG emissions.
- **Federal Government**: The U.S. government has taken steps to reduce GHG emissions from energy use in federal buildings and in the federal transportation fleet.

A summary of the estimated CO_2-equivalent GHG reductions gained by implementation of various federal programs, as outlined in the 2002 U.S. Climate Action Report, is provided in Table D-2. Based on the sector totals provided in the report, the U.S. has avoided over 240 MMT of CO_2-equivalent since the inception of these programs. The report also projects that this amount will increase over 2.5 times by 2010. These projections were made assuming a similar level of funding would continue for these programs as that provided in 2002. Based on these projections, it is estimated that combined, these programs could contribute an average CO_2-equivalent reduction or avoidance at a rate of 40 MMT/year (2010 total minus 2000 total divided by 10 years).

Table D-2. Estimated CO_2 Mitigation Impacts of Other Federal Programs

Name of Policy or Measure	Estimated CO_2 Mitigation Impact for 2000 (MMT CO_2 Eq.)*	Estimated CO_2 Mitigation Impact for 2010 (MMT CO_2 Eq.)
Energy: Commercial and Residential	56.8	Not available (est. 157)
Energy Star® for the Commercial Market	23	62
Energy Star® for the Residential Market	NA	20
Energy Star® - Labeled Products	33	75
Energy: Industrial	27.9	Not available (est. 34)
Energy Star® for Industry (Climate Wise)	11	16
Energy: Supply	14.7	Not available (est. 30)
Clean Energy Initiative	NA	30
Transportation	8.4	Not available (est. 43)
Commuter Options Program	3.5	14
Smart Growth and Brownfields Policies	2.7	11
Ground Freight Transportation Initiative	NA	18
Industry (Non-CO_2)*	88.7	Not available (est. 325)
Natural Gas Star Program	15	22
Coalbed Methane Outreach Program	7	10
Significant New Alternatives Program	50	162
HFC-23 Partnership	17	27
Partnership with Aluminum Producers	8	10

Name of Policy or Measure	Estimated CO_2 Mitigation Impact for 2000 (MMT CO_2 Eq.)*	Estimated CO_2 Mitigation Impact for 2010 (MMT CO_2 Eq.)
Environmental Stewardship Initiative	3	94
Waste Management	39.2	Not available (est. 75)
Climate and Waste Program	8	20
Stringent Landfill Rule	15	33
Landfill Methane Outreach Program	11	22
Cross-Sectoral (Federal Energy Management Program and State/Local Climate Change Outreach Program)	6.2	Not available.
All Programs	241.9 (Sector Totals)	1310 (Individual Program Totals)
Sector totals are those reported in Table 4-1 of the 2002 U.S. Climate Action Report. As the report did not project sector totals for 2010, estimated numbers are shown based on the projections for individual programs within that sector. Program specific carbon reduction numbers were obtained within the text of chapter 4 of the same report. Source: U.S. Department of State, 2002.		

D.2.2 State and Regional Programs

D.2.2.1 RGGI

As discussed in Appendix A, nine Northeast and Mid-Atlantic states signed a Memorandum of Understanding to implement the Regional Greenhouse Gas Initiative. The goal of this initiative is to reduce CO_2 emissions by 10 percent of its initial annual budget by 2018. If this goal were attained, collectively the region would reduce CO_2 emissions by 11 MMT from annual baseline levels.

D.2.2.2 State of California

On June 1, 2005, California Governor Arnold Schwarzenegger issued an Executive Order (EO) that established a series of greenhouse gas reduction targets for the state. Included within the EO is a charge for the California Environmental Protection Agency secretary to oversee the efforts to achieve the Governor's standards (State of California, 2005). The EO states targets of:

- Reductions to 2000 levels (370.4 MMT CO_2 Eq.) by 2010;
- Reductions to 1990 levels (322.8 MMT CO_2 Eq.) by 2020; and
- Reductions to 80 percent below 1990 levels (64.56 MMT CO_2 Eq.) by 2050.

D.3 INTERNATIONAL SEQUESTRATION AND GHG REDUCTION INITIATIVES

D.3.1 Carbon Sequestration Leadership Forum (CSLF)

The CSLF is an international climate change initiative that is focused on development of improved cost-effective technologies for the separation and capture of carbon dioxide for its transport and long-term safe storage. The purpose of the CSLF is to make these technologies broadly available internationally; and to identify and address wider issues relating to carbon capture and storage. This could include promoting the appropriate technical, political, and regulatory environments for the development of such technology. Three types of cooperation are currently envisioned within the framework of the Forum: (1) data gathering; (2) information exchange; and, (3) joint projects. At the second CSLF ministerial meeting in September 2004, 10 joint projects were recognized (DOE, 2004). The U.S. is participating in 7 of the 10 joint projects, listed below:

- *ARC Enhanced CBM Recovery Project (Canada, United States and United Kingdom)*. Evaluate, from both economic and environmental criteria, a process of CO_2 injection into deep coal beds for simultaneous sequestration of the CO_2 and liberation (and subsequent capture) of coal-bed methane.
- *CANMET Energy Technology Centre (CETC) R&D Oxyfuel Combustion for CO_2 Capture (Canada and United States)*. Demonstrate oxyfuel combustion technology with capture of a high-purity CO_2 design and operation of industrial and utility plants based on the oxyfuel concept.
- *CO_2 Capture Project, Phase II (United Kingdom, Norway, Italy, and United States)*. Continue the development of new technologies to reduce the cost of CO_2 separation, capture, and geologic storage from combustion sources such as turbines, heaters and boilers.
- *CO_2 Separation from Pressurized Gas Stream (Japan and United States)*. Evaluate processes and economics for CO_2 separation from pressurized gas streams with gas separation membranes.
- *Frio Project (United States and Australia)*. Demonstrate CO_2 sequestration in an on-shore underground saline aquifer in order to verify conceptual models and monitoring methods, demonstrate that no adverse health, safety or environmental effects will occur, and develop experience necessary for larger-scale experiments.
- *ITC CO_2 Capture with Chemical Solvents (Canada and United States)*. Demonstrate CO_2 capture using chemical solvents, with a goal of developing improved cost-effective technologies for separation and capture of CO_2 from flue gas.
- *Weyburn II CO_2 Storage Project (United States, Canada, and Japan)*. Utilize CO_2 for enhanced oil recovery at a Canadian oil field, including monitoring CO_2 migration within the oil field, with a goal of determining the overall performance and risks in using CO_2 for enhanced oil recovery.

The portions of these projects to be conducted in the U.S. would be similar in size and scope to the model projects developed under this document. Subsequently, impacts associated with these projects would be similar to those predicted in this document.

D.3.2 Tropical Forest Conservation Act

As of June 2004, seven countries have Tropical Forest Conservation Act (TFCA) agreements: Bangladesh, Belize, Colombia, El Salvador, Panama, Peru, and the Philippines. These agreements are offered to eligible developing countries to relieve certain official debt owed the United States while at the same time generating funds to support local tropical forest conservation activities that store carbon. These agreements will generate over $70 million for tropical forest conservation in countries over the life of the agreements. Based on previous agreements under the TFCA, this funding could preserve approximately 8 to 75 million acres of land in these countries (USAID, 2005). Land preservation resulting from the TFCA would provide net positive benefits to the environment.

D.3.3 President's Initiative Against Illegal Logging

On July 28, 2003, the President's Initiative Against Illegal Logging was launched with the objective of assisting developing countries combat illegal logging, including the sale and export of illegally harvested timber, and in fighting corruption in the forestry sector. The initiative represents the most comprehensive strategy undertaken by any nation to address this critical challenge to sustainable development, and reinforces the U.S.'s leadership role in countering the problem and preserving forest resources that store carbon (White House, 2004). Forests preserved as a result of this initiative would provide net positive benefits to the environment.

D.3.4 The Kyoto Protocol

The Kyoto Protocol is an amendment to the United Nations Framework Convention on Climate Change (UNFCCC) with the purpose of stabilizing atmospheric greenhouse gas concentrations at levels that would prevent any anthropogenic disturbance of the global climate system. As of January 2006, 160 countries had ratified the agreement without the participation of the U.S. Under the agreement industrialized countries will reduce their emissions of greenhouse gases by a total of 5.2 percent in relation to 1990 emissions levels. The agreement actively came into force on February 16, 2005 (Wikipedia, 2006).

A major component of Kyoto involves an international emissions trading market that allows countries with emissions levels below their set limits to sell credits to countries with levels exceeding their limits. Credits are also received by countries through shared clean energy programs and carbon dioxide sinks, which include forests or other systems that sequester carbon dioxide from the atmosphere (Wikipedia, 2006).

The goals of the Kyoto Protocol are primarily concerned with halting the net increase of atmospheric GHG emissions. Therefore, under the agreement some developing countries will be permitted to increase GHG emissions, which will be offset by reductions employed by currently industrialized nations. Table D-3 lists countries that are included in Annex B of the Kyoto Protocol and their emissions projections based on Kyoto's targets. Countries included in Annex B are developed nations that have agreed to certain targets for GHG emissions and may actively participate in the international emissions trading market. Annex B nations are expected to, in total, reduce their CO_2 emissions by 4.85 percent by 2012 as compared to 1990 emissions levels based on imposed emissions targets (UNFCCC, 2006a).

The highest decision making body within the UNFCCC is the Conference of the Parties (COP), which is an association of all the nations that are parties to the convention. The COP meets yearly to discuss the status of, and potential remedies for, climate change, which includes discussion of Kyoto as well as other longer-term prospects (UNFCCC 2005).

The most recent United Nations Climate Change Conference occurred in Montreal from November 28 through December 9, 2005. During this meeting the eleventh session of the Conference of the Parties (COP 11) was convened. Several substantial decisions came to pass as a result of the conference. The COP decided to adopt the Marrakech Accords, which is considered the rulebook for the Kyoto Protocol, allowing the formal implementation of the Protocol to commence. They adopted a decision that created a formal open dialogue on long-term cooperative action to address climate change, which includes advancing development goals in a sustainable manner, addressing action on adaptation, implementing technology to its fullest potential, and realizing market-based options to their fullest extent. They also established a working group specifically tasked to discuss commitments for developed countries beyond the 2012 commitments currently set forth in Kyoto (UNFCCC 2005).

Due to the fact that the Kyoto Protocol will result in reduced GHG emissions, the implementation of the agreement is expected to have an overall beneficial impact to the environment, although it is acknowledged that further GHG reduction goals and measures are necessary to have a significant impact on global warming.

Table D-3. Estimated Atmospheric CO_2 Impacts of the Kyoto Protocol's Annex B Countries

Party	Baseline 1990 CO_2 Emissions (Metric Tons)[a]	2003 CO_2 Emissions (Metric Tons)[a]	Emissions Targets (1990/2012)[b]	Total Emissions Projection for 2012 (Metric Tons)
European Union*	3,111,220,000	3,138,320,000	-8%	2,862,322,400
United States**	3,967,500,000	5,013,460,000	-7%	3,689,775,000
Canada	304,390,000	540,200,000	-6%	286,126,600
Hungary	83,430,000	56,500,000	-6%	78,424,200
Japan	1,038,370,000	1,116,380,000 (1995)***	-6%	976,067,800
Poland	441,880,000	257,580,000 (2002)***	-6%	413,367,200
Croatia	10,350,000	7,630,000	-5%	9,832,500
New Zealand	3,940,000	11,830,000	0%	3,940,000
Russian Federation	2,516,950,000	1,297,260,000 (1999)***	0%	2,516,950,000
Ukraine	699,180,000	257,380,000	0%	699,180,000
Norway	20,950,000	22,250,000	1%	21,159,500
Australia	382,030,000	402,280,000	8%	412,592,400
Iceland	2,080,000	1,970,000	10%	2,288,000
Total	12,582,270,000	12,122,740,000		11,972,025,600
Total CO_2 Reduction 1990 – 2012 (Metric Tons)	610,244,400			
Net CO_2 Reduction Percentage (1990-2012)	4.85%			
Total CO_2 Reduction 2003 – 2012 (Metric Tons)	150,714,400			
Net CO_2 Reduction Percentage (2003 – 2012)	1.24%			

* The European Union consists of its 15 member States.
** The U.S. has not ratified the Kyoto Protocol as of February 2006.
*** Indicates the most recent year with data available.
Source: [a] UNFCCC, 2006; [b] UNFCCC, 2006a.

D.4 CUMULATIVE IMPACTS OF CARBON SEQUESTRATION PROGRAMS AND POLICIES

The implementation of carbon sequestration technologies that would be expected to cause impacts to the environment, whether under the DOE's program or other federal, state, or private sector initiatives, would be subject to existing federal and state environmental laws and regulations. These regulations principally include the CAA, CWA, SDWA, EPCRA, RCRA, Toxic Substance Control Act (TSCA), the CERCLA, and the ESA. Federal actions would also be subject to additional scrutiny and requirements under NEPA and other acts and executive orders (e.g.; NHPA). Lastly, depending upon the location of a particular action, state and/or local controls could provide additional project-specific controls (e.g.; land use controls, noise ordinances, etc.).

Other U.S. carbon sequestration programs and policies would provide additional means to sequester carbon or sustain or enhance vegetated lands in the U.S. or abroad that currently sequester carbon. Although the scope of carbon sequestration activities being promoted and implemented by the DOE and others have not been fully determined, it is expected that at a minimum these activities would conform to all federal and state laws as applicable. Due to the presence of these laws, acts, and the regulatory programs, the potential for project-specific related impacts when considered on the national scale are expected to minimal. Subsequently, potential adverse impacts to the environment or human health and safety from the program are expected to be minimal.

The primary area of potential cumulative impacts of these programs and policies would be in the area of land use. Lands in the U.S. used for farming and agriculture would utilize new methods that enhance carbon uptake and retention. Formerly mined lands may receive additional funding to undertake reforestation projects, where the land would be preserved as a carbon sink. There is also the possibility that other types of private or public undeveloped lands would be preserved as carbon sinks in the U.S. International programs and policies (such as TFCA and the Initiative Against Illegal Logging) that serve to preserve land abroad as carbon sinks would complement and advance the goals of the domestic Carbon Sequestration Program.

However, the overall cumulative impact of programs that sequester carbon, including the DOE's program, is expected to provide an overall benefit to the environment, as they would help reduce the accumulation of greenhouse gases that contribute to global warming. Research programs conducted by other federal agencies, like NOAA, USDA and EPA, would also complement the DOE’s Carbon Sequestration Program by providing data and tools that would aid future technology development or provide monitoring and data collection mechanisms.

Joint carbon sequestration projects that the U.S. will undertake with other countries, as developed under the CSLF would likely be conducted under, or in coordination with, the DOE’s program. These field validation projects are likely to be conducted in part or in whole at U.S. sites. As the U.S. participates in future projects under the CSLF, the DOE’s R&D program may be expanded by providing not only additional data to support the program, but may require additional field testing locations and land area in the U.S.

D.5 IMPACTS OF GLOBAL WARMING

While there is serious debate whether or not global warming can be halted or even reversed, there is little doubt that GHG concentrations in the earth’s atmosphere are on the increase, with potential linkages to human activities. The rate of the melting of the polar icecaps and the increasing rates of thawing of permafrost in areas like Alaska are expected to increase the rate of global warming – to the extent that global warming may be unavoidable, despite mankind’s recent attempts to reduce GHG emissions.

Nonetheless, because of the severity of potential impacts of increased global warming, the U.S. is committed to continuing to take steps through numerous federal programs to reduce anthropogenic CO_2 and other GHG emissions.

According to EPA, as the climate changes, natural systems will be destabilized, which could pose a number of risks to human health (EPA, 1997). Temperature increases, precipitation changes and sea level rise will likely cause: heat waves, air pollution, terrestrial changes, altered marine ecology, storms, droughts, population displacement and saltwater encroachment in coastal aquifers (EPA, 1997). Figure D-1 provides the types of health impacts anticipated from these environmental effects. More information on these effects can be found in EPA circular 236-F-97-005 dated October 1997 titled “Climate Change and Public Health”.

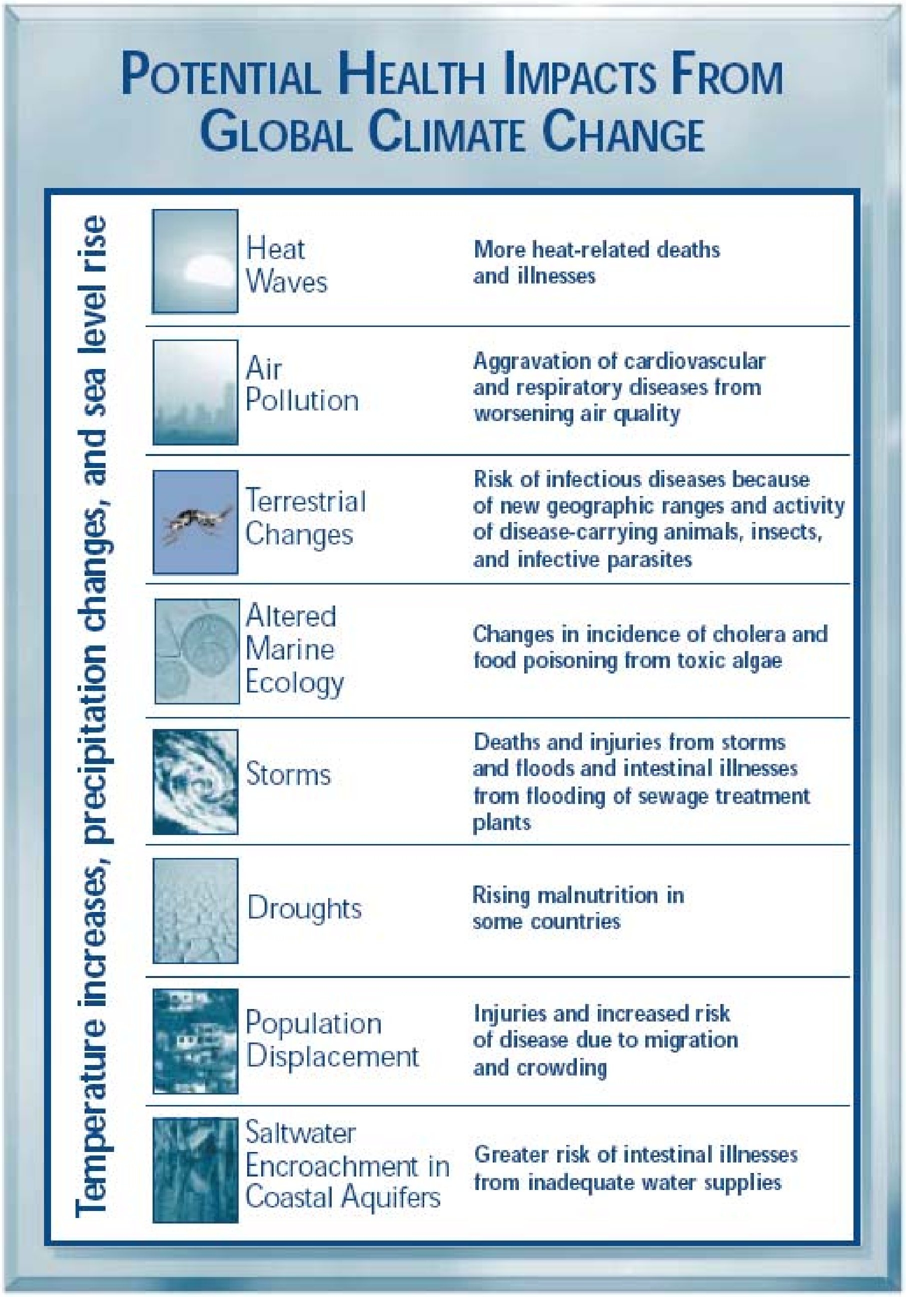

Figure D-1. Potential Health Impacts from Global Climate Change

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