



Plains CO₂ Reduction (PCOR) Partnership
Practical, Environmentally Sound CO₂ Sequestration



DEPLOYMENT ISSUES RELATED TO GEOLOGICAL AND TERRESTRIAL CO₂ SEQUESTRATION IN THE PCOR PARTNERSHIP REGION

Topical Report

Prepared for:

Mr. John T. Litynski

Carbon Sequestration Project Manager
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

Thea E. Reilkoff
Lisa S. Botnen
Steven A. Smith
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
PO Box 9018
Grand Forks, ND 58202-9018

F. Larry Leistritz
Dean A. Bangsund

Department of Agribusiness and Applied Economics
North Dakota State University
PO Box 5636
Fargo, ND 58105-5636

May 2005





TABLE OF CONTENTS

LIST OF TABLESiv

EXECUTIVE SUMMARY 1

ACKNOWLEDGMENTS 3

BACKGROUND/INTRODUCTION 5

GENERAL PHYSICOCHEMICAL PROPERTIES OF CO₂ 5

ECOLOGICAL AND ENVIRONMENTAL IMPACTS OF GEOLOGICAL STORAGE..... 6

 Operational Risks 8

 Pipelines 8

 Wells 9

 In Situ Risks: Pathways of CO₂ Migration 9

 Direct Release to the Atmosphere 10

 Natural and Induced Seismicity 10

 Migration to Overlying Freshwater Sources 11

 Transformation 11

 Additional Concern for Ecological and Environmental Impacts 11

 Lessons Learned from Natural and Industrial Analogs 12

ECOLOGICAL AND ENVIRONMENTAL IMPACTS OF TERRESTRIAL SEQUESTRATION..... 13

MEASUREMENT, MITIGATION, AND VERIFICATION OF GEOLOGICAL CARBON CAPTURE AND STORAGE 13

 Elements of MM&V 14

 MM&V Methods 15

 Geophysical Monitoring Practices: Seismic, Electrical, and Gravity Measurement 15

 Analysis of CO₂ Flow Rates and Injection and Formation Pressures 20

 Analysis of Well Logs 20

 Direct Measurement of CO₂ 20

 Geochemical Methods and Tracers 21

 Land Surface Deformation and Spectral Imaging 21

 Pipeline Monitoring and Testing 21

Continued . . .



TABLE OF CONTENTS (continued)

Frequency of Monitoring	22
Modeling	22
Status of MM&V Technologies for Use in Monitoring CO ₂	22
Weyburn CO ₂ Monitoring and Storage Project	22
Saline Aquifer CO ₂ Storage (SACS) Monitoring Project, North Sea, Norway.....	23
Frio Brine Pilot Experiment, Texas.....	24
West Pearl Queen Field, New Mexico	24
Ohio River Valley CO ₂ Storage Project, West Virginia.....	24
Texas Technical University	25
GEO-SEQ Project	25
Rocky Mountain Oil Field Testing Center (RMOTC), Teapot Dome.....	25
Additional Research Considerations.....	25
Regulatory Requirements and Considerations for MM&V in Geological Sequestration	26
MM&V Strategies for the PCOR Partnership Region.....	27
General Requirements for Geological Sequestration	27
Additional Considerations for EOR and Storage in Depleted Oil Reservoirs	28
Additional Considerations for Storage in Deep Saline Formation	29
Additional Considerations for Storage in Unminable Coal Seams or for ECBM Recovery.....	29
MM&V Implementation Plan for Geological Sequestration Options in the Region.....	29
 MEASUREMENT, MONITORING, AND VERIFICATION OF TERRESTRIAL SEQUESTRATION.....	 31
Technologies and Strategies for Measuring, Monitoring, and Verifying Terrestrial CO ₂ Sequestration	31
Soil Carbon Measurements.....	31
Simulation Models and Scaling.....	33
Biomass Carbon Measurements.....	33
Eddy Covariance Measurements	33
Remote Sensing.....	34
Voluntary Reporting of GHG Emissions for 1605(b) Program	34
Verification for Carbon Credit Trading.....	34
Measurement, Monitoring, and Verification Strategies for the PCOR Partnership Region	34
Alternative Agricultural Practices and Wetland Restoration	35
Forestry and Agroforestry	35
Monitoring, Measurement, and Verification Implementation Plan for Terrestrial Sequestration Options in the Region	36

Continued . . .



TABLE OF CONTENTS (continued)

REGULATING CARBON CAPTURE AND GEOLOGICAL STORAGE 37

 U.S. Regulatory Framework 38

 Capture and Separation 38

 Transportation 40

 CO₂ Injection and the Underground Injection Control (UIC) Program 41

 The Natural Gas Storage 48

 National Environmental Policy Act 49

 Long-Term Management and Liability Issues 49

 Canadian Regulatory Framework 50

 CO₂ Capture 51

 Pipeline Transportation 51

 CO₂ Injection and Storage 51

 MM&V 52

 Mitigation of Risk 52

 Liability and Long-Term Management 52

 Considerations in Developing a Regulatory Framework for Long-Term Storage 53

 Definition 53

 Capture and Transport 53

 Site Selection 54

 Injection 55

 Monitoring and Verification 57

 Mitigation and Remediation 57

 Long-Term Management and Liability 57

 Procedural vs. Performance-Based Regulations 58

CONCLUSIONS 59

REFERENCES 60

GEOLOGICAL VARIABLES AND THEIR ASSOCIATED UNCERTAINTIES Appendix A

CODE OF FEDERAL REGULATIONS (CFR) RELATING TO
CARBON DIOXIDE Appendix B

CO₂ CAPTURE AND STORAGE STATUTORY AND REGULATORY
REVIEW – CANADA Appendix C

KEY FEDERAL LEGISLATION THAT COULD AFFECT CARBON
SEQUESTRATION PROJECTS Appendix D



LIST OF TABLES

1 Acute Health Effects of Human Exposure to High Concentrations of CO₂ 6

2 Summary of Local Risks of CO₂ Migration out of the Storage Formation..... 8

3 Monitoring Methods Applicable to Geological CO₂ Sequestration..... 16

4 Monitoring, Measurement, and Verification Methods Applicable to Terrestrial
CO₂ Sequestration 32

5 Pipeline Permitting Authority for the United States Within the PCOR
Partnership Region 41

6 EPA UIC Program Injection Well Classification System..... 42

7 Enforcement of UIC Program for the PCOR Partnership Region..... 43

8 Siting and Construction Requirements for Class I and II Injection Wells 45

9 Operation and Monitoring Requirements for Class I and II Injection Wells..... 46

10 Reporting and Record-Keeping Requirements for Class I and II Injection Wells..... 47

11 Closure and Abandonment Requirements for Class I and II Injection Wells 48



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Thea E. Reilkoff, Energy & Environmental Research Center
Lisa S. Botnen, Energy & Environmental Research Center
Steven A. Smith, Energy & Environmental Research Center
F. Larry Leistritz, Department of Agribusiness and Applied Economics,
North Dakota State University
Dean A. Bangsund, Department of Agribusiness and Applied Economics,
North Dakota State University
Edward N. Steadman, Energy & Environmental Research Center
John A. Harju, Energy & Environmental Research Center

May 2005

EXECUTIVE SUMMARY

A great breadth of information has been published addressing the environmental and ecological impacts of terrestrial and geological sequestration, the need for a regulatory framework to deal with these issues, and the tools and knowledge available and yet needed for ensuring safe and effective storage of CO₂. This report provides an overview of the current literature and guidance for the development of future projects in the Plains CO₂ Reduction (PCOR) Partnership region. The topics covered in this report include environmental, health, and safety risks posed by terrestrial and geological CO₂ sequestration activities; measurement, monitoring, mitigation, and verification techniques and requirements; and the applicability of the current regulatory framework for carbon capture and geological storage.

To ensure the safe and effective capture and storage of CO₂, projects must identify and evaluate potential ecological and environmental impacts, effectively monitor and assess storage efficiency, and be

prepared to take remedial action in the event of failure. The risks associated with CO₂ sequestration are typically divided into two categories: 1) local environmental impacts, including risks to the environment and human health and safety and 2) global atmospheric impact arising from leaks that return stored CO₂ to the atmosphere. While low levels of CO₂ are essential for life, elevated concentrations of CO₂ in shallow subsurface soils or overlying air can adversely affect local ecology, including humans. Elevated atmospheric concentrations of CO₂ may influence the global climate.

The capture, processing, transportation, and injection of CO₂ for geological storage are proven practices with well-known risks and established risk management strategies. Potential hazards typically involve pipeline or well failure caused by corrosion, vibration, external impact, operator error, inadequate maintenance, or equipment degradation (Vendrig, M., Spouge, J., Bird, A., Daycock, J., and Johsen, O., 2003, Risk analysis of the geological sequestration of carbon dioxide: No. R DTI/pub., prepared for Department

of Trade and Industry's Cleaner Coal Technology Transfer Programme). Engineering controls and specifications for transportation, storage containers, pipelines, and well construction and operation limit the likelihood of catastrophic failures.

Unlike operational risks of geological storage, in situ risks arising from subsurface migration of CO₂ are far less defined and understood. In order to ensure safe and effective long-term storage of CO₂, thorough investigation is needed of the chemical and physical properties of the local geology as well as geochemical, geophysical, and hydrological interactions with CO₂ injection. Pathways of migration include direct and indirect losses of CO₂ to the atmosphere from the subsurface through existing fractures or faults in the confining caprock; natural or induced seismic events; water movement; vegetation; and poorly constructed or sealed injection, monitoring, or production wells. In addition to direct and indirect losses to the atmosphere, transformation within the geological reservoir, including mineralization and demineralization, can occur.

There are numerous natural and industrial analogs to geological CO₂ sequestration from which lessons can be learned for assessing and mitigating risks. These include natural accumulations of CO₂ in the subsurface, natural subsurface releases of CO₂ (i.e., volcanic eruptions, limnic releases, hydrothermal vents, diffuse venting), disposal of industrial liquid waste in deep geological formations, underground natural gas storage, enhanced recovery operations, nuclear waste disposal, and industrial handling of CO₂.

Unlike geological carbon storage, terrestrial sequestration, as conducted today, poses no risk to human health and safety resultant of direct CO₂ exposure. While

local and global risks may arise with terrestrial sequestration, a majority of terrestrial sequestration methods will actually provide added benefits to the environment (i.e., improvement in soil health, reduced erosion, enhancement of wildlife habitat, etc.). The few risks that may exist in terrestrial sequestration projects are generally associated with human- or nature-induced forest fires; the use of nutrient amendments, pesticides, or herbicides to promote biomass growth; and changes in land management practices, which negate sequestration gains.

Assessing the effectiveness of terrestrial or geological sinks for storing CO₂ is critical. Measurement, mitigation, and verification (MM&V) strategies will be required through all phases of geological CO₂ sequestration, including capture and separation, transportation, injection, and long-term storage. The implementation of MM&V serves to 1) protect worker health and safety; 2) ensure environmental and ecological safety; 3) verify safe and effective storage, including providing assurances of carbon credits of transactions in a carbon-trading market; 4) track plume migration; 5) provide early warning for failure; and 6) confirm model predictions.

The primary elements associated with the MM&V of geological CO₂ sequestration can be divided into two categories: 1) the careful monitoring of engineered systems and 2) monitoring of CO₂ migration within and out of the primary storage reservoir. Numerous well-established procedures and monitoring technologies are in use by industry that are applicable to CO₂ sequestration. To date, however, there is no standard procedure for monitoring the effectiveness and safety of CO₂ capture and geological storage. While current technology demonstrations are necessary to identify adequate methods for assessing CO₂ sequestration, variances in geological storage formations, injection volumes, and gas compositions will complicate the

development of broad-scale MM&V strategies.

Because storage of CO₂ in terrestrial ecosystems, as conducted today, poses no direct risk to human health and safety resultant of CO₂ exposure requirements, monitoring, measurement, and verification are solely for accounting purposes in a greenhouse gas market. Several approaches are currently used to estimate carbon stored as a result of a particular land management practice. These approaches include:

- Direct measurement of soil carbon, biomass, or CO₂ flux.
- Indirect remote sensing techniques.
- Use of default values assigned to various land use practices.

These approaches may be used independently or may be combined depending on the level of accuracy required for monitoring and verification efforts.

The development of a science-based regulatory framework designed with the flexibility required to encourage reduction of CO₂ emissions while providing protection for environmental and human health and verification of effective storage is a prerequisite for large-scale CO₂ sequestration (Forbes, S.M., 2002, Regulatory barriers for carbon capture, storage and sequestration: National Energy Technology Laboratory, p. 7). At this time, the demonstration and implementation of CO₂ sequestration is outpacing development of appropriate regulations. Although there are challenges in establishing a regulatory framework for CO₂ storage, the issue has been recognized, and current research will only help to better define the needs. Today, the difficulty in developing an effective regulatory framework for long-term CO₂ storage is not simply a factor of technical uncertainty in predicting the lifetime of a

given storage reservoir, but is instead closely tied to the uncertainty regarding what is required to effectively mitigate climate change (e.g., a clearly defined acceptable leakage rate).

The PCOR Partnership has the advantage of having a great deal of experience and history in extractive operations. With recent advancements in monitoring CO₂ storage at the Weyburn Field in Saskatchewan, the PCOR Partnership region is poised for near-term demonstration of additional capture and geological storage opportunities.

ACKNOWLEDGMENTS

The PCOR Partnership is a collaborative effort of public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing (sequestering) anthropogenic carbon dioxide (CO₂) emissions from stationary sources in the central interior of North America. It is one of seven regional partnerships funded by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) Regional Carbon Sequestration Partnership (RCSP) Program. The Energy & Environmental Research Center (EERC) would like to thank the following partners who provided funding, data, guidance, and/or experience to support the PCOR Partnership:

- Alberta Department of Environment
- Alberta Energy and Utilities Board
- Alberta Energy Research Institute
- Amerada Hess Corporation
- Basin Electric Power Cooperative
- Bechtel Corporation
- Center for Energy and Economic Development (CEED)
- Chicago Climate Exchange
- Dakota Gasification Company
- Ducks Unlimited Canada
- Eagle Operating, Inc.

- Encore Acquisition Company
- Environment Canada
- Excelsior Energy Inc.
- Fischer Oil and Gas, Inc.
- Great Northern Power Development, LP
- Great River Energy
- Interstate Oil and Gas Compact Commission
- Kiewit Mining Group Inc.
- Lignite Energy Council
- Manitoba Hydro
- Minnesota Pollution Control Agency
- Minnesota Power
- Minnkota Power Cooperative, Inc.
- Montana–Dakota Utilities Co.
- Montana Department of Environmental Quality
- Montana Public Service Commission
- Murex Petroleum Corporation
- Nexant, Inc.
- North Dakota Department of Health
- North Dakota Geological Survey
- North Dakota Industrial Commission Lignite Research, Development and Marketing Program
- North Dakota Industrial Commission Oil and Gas Division
- North Dakota Natural Resources Trust
- North Dakota Petroleum Council
- North Dakota State University
- Otter Tail Power Company
- Petroleum Technology Research Centre
- Petroleum Technology Transfer Council
- Prairie Public Television
- Saskatchewan Industry and Resources
- SaskPower
- Tesoro Refinery (Mandan)
- University of Regina
- U.S. Department of Energy
- U.S. Geological Survey Northern Prairie Wildlife Research Center
- Western Governors’ Association
- Xcel Energy

The EERC also acknowledges the following people who assisted in the review of this document:

Lynn D. Helms, North Dakota Industrial Commission
 Stefan Bachu, Alberta Energy and Utilities Board
 Erin M. O’Leary, EERC
 Kim M. Dickman, EERC
 Stephanie L. Wolfe, EERC

BACKGROUND/INTRODUCTION

As one of seven Regional Carbon Sequestration Partnerships (RCSPs), the Plains CO₂ Reduction (PCOR) Partnership is working to identify cost-effective CO₂ sequestration systems for the PCOR region and, in future efforts, to facilitate and manage the demonstration and deployment of these technologies. In this phase of the project, the PCOR Partnership is characterizing the technical issues, enhancing the public's understanding of CO₂ sequestration, identifying the most promising opportunities for sequestration in the region, and detailing an action plan for the demonstration of regional CO₂ sequestration opportunities. This report focuses on environmental, health, and safety risks of geological and terrestrial CO₂ sequestration; measurement, mitigation, and verification (MM&V) strategies and requirements; and considerations for regulatory oversight and applicability of the current regulatory framework for geological CO₂ sequestration.

While it is likely to take several decades for geological sequestration to be implemented as a large-scale means for mitigating atmospheric buildup of CO₂, the development and utilization of capture and storage projects have begun. In order to ensure safe and effective geological sequestration, assessment of ecological and environmental impacts and development of an adequate regulatory framework must lead broad-scale technology implementation. In the near term, projects will focus on characterizing potential storage reservoirs, understanding geophysical and geochemical interactions with CO₂ injection, identifying and understanding risks, developing and testing technologies for MM&V of capture and storage, and defining regulatory requirements that effectively meet sequestration goals.

As research on geological capture and storage progresses, terrestrial sequestration will undoubtedly serve as a near-term option for transitory storage. Most methods for sequestering carbon in terrestrial systems can be implemented today without regulatory oversight or the need for assessing storage efficiency. If, however, sequestration activities involve the exchange of carbon credits, measurement, monitoring, and verification of carbon storage will be required for accounting purposes.

This report serves to provide an overview of current literature and guidance for the development of future projects in the PCOR Partnership region. As development of potential sequestration projects is further explored in this region, additional information, including project-specific permitting requirements and strategies for measurement, monitoring, verification, mitigation, and risk identification, will be prepared as part of a comprehensive action plan.

GENERAL PHYSICOCHEMICAL PROPERTIES OF CO₂

Carbon dioxide is a colorless, odorless, noncombustible gas present in low concentrations in the Earth's atmosphere. It is produced through processes of cellular respiration, fermentation of sugars, and decomposition or combustion of carbon-containing matter. It has a density greater than air, a critical temperature of 31°C (87.7°F), and a critical pressure of 7.4 MPa (1073 psi). CO₂ is essential in biologic processes but can pose adverse health effects when exposure concentrations are elevated.

The current ambient atmospheric concentration of CO₂ is about 370 ppm, up from preindustrial levels of 280 ppm. Below 1% (10,000 ppm) CO₂, humans, flora, and fauna experience virtually no adverse health effects. Human exposure to

between 1% and 5% CO₂ can result in increased respiratory rate and mild discomfort. Above 5%, physical and mental capacity is impaired, and loss of consciousness can occur. Exposure to more than 10% CO₂ can result in rapid loss of consciousness, possible coma, or death (Benson et al., 2002). Table 1 shows acute health effects for human exposure. While plants, insects, and soil organisms have a higher tolerance to elevated CO₂ concentrations, in general, only a few microbes, invertebrates, insects, and fungi can survive in CO₂ concentrations in excess of 20%. Small, short-term CO₂ leaks typically pose minimal threat to plant life; however, persistent leaks can result in soil acidification and respiratory suppression in the root zone.

Assuming a geothermal gradient of 15°F/1000 ft and a pressure gradient of 0.433 psi/ft, CO₂ will reside in a dense, supercritical gas phase when sequestered in a confined geological formation of depth greater than approximately 2600 ft

(www.glossary.oilfield.slb.com). In its supercritical state, CO₂ has a density and viscosity less than water and, therefore, has a strong tendency to migrate to the top of the injection zone, thereby driving horizontal movement and increasing the areal extent of the CO₂ plume more than would be observed with a neutrally buoyant fluid (Tsang et al., 2002). A portion of the injected CO₂ will dissolve in the aqueous phase, and a portion will be available to react with rock minerals. When CO₂ dissolves in hydrocarbons, it acts as a solvent, reducing hydrocarbon viscosity and increasing mobility.

ECOLOGICAL AND ENVIRONMENTAL IMPACTS OF GEOLOGICAL STORAGE

To ensure safe and effective geological storage of CO₂, projects must identify and evaluate potential ecological and environmental impacts, effectively monitor and assess storage efficiency, and be prepared to take remedial action in the event of failure. The risks associated with CO₂ sequestration are typically divided into

Table 1. Acute Health Effects of Human Exposure to High Concentrations of CO₂ (Vendrig et al., 2003)

CO ₂ Concentration		Time	Effects
Percentage	ppm		
17-30	170,000-300,000	Within 1 minute	Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death
>10-15	100,000-150,000	1 minute to several minutes	Dizziness, drowsiness, severe muscle twitching, unconsciousness
7-10	70,000-100,000	A few minutes	Unconsciousness, near unconsciousness
		1.5 minutes to 1 hour	Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing
6	60,000	1-2 minutes	Hearing and visual disturbances
		<16 minutes	Headache, dyspnea
		Several hours	Tremors
4-5	40,000-50,000	Within a few minutes	Headache, dizziness, increased blood pressure, uncomfortable dyspnea
3	30,000	1 hour	Mild headache, sweating, and dyspnea at rest
2	20,000	Several hours	Headache, dyspnea upon mild exertion

two categories: 1) local environmental impacts, including risks to the environment and human health and safety and 2) global atmospheric impacts arising from leaks that return stored CO₂ to the atmosphere.

Local risks may arise from:

- Elevated CO₂ in the shallow subsurface or atmosphere.
- Chemical effects of dissolved CO₂ in subsurface fluids.
- The displacement of fluids or gases by injected CO₂.

While low levels of CO₂ are essential for life, elevated concentrations of CO₂ in shallow subsurface soils or overlying air can cause significant damage to local biota, soil microbes, insects, burrowing animals, and ground-dwelling animals, including humans. Risks associated with surface releases of CO₂ are highly variable and dependent on the volume of the release, time over which the release occurs, and surface topography. Because CO₂ is denser than air, it tends to pool in topographical depressions and confined or poorly ventilated areas, displacing oxygen and increasing the hazards of exposure to elevated CO₂ concentrations. The most evident risk of exposure to elevated concentrations of CO₂ is associated with the potential for well blowouts, pipeline failures, or subsurface events resulting in catastrophic releases of large volumes of CO₂ over a relatively short period of time. While such catastrophic risks tend to attract widespread attention, slow, persistent surface leaks pose risks that may be much more difficult to manage.

Local risks arising from the migration of CO₂ within the subsurface can include the mobilization of metals or organic compounds, contamination of potable water sources, disruption of deep subsurface ecosystems, and displacement

of existing subsurface liquids and materials. Vertical migration of CO₂ to freshwater aquifers has the potential to alter the pH of the water supply through dissolution and formation of carbonic acid. Any change in pH can negatively impact geochemistry, water quality, and ecosystem health (Bruant et al., 2002).

The injection of large volumes of fluid can result in the displacement of original formation fluids and materials. Effects of displacement can be manifested as local ground heave, induced seismicity, contamination of overlying potable water sources by displaced brines or organic contaminants, and damage to hydrocarbon or mineral resources. Table 2 and subsequent sections provide a further summary of the local risks associated with CO₂ migration out of the storage formation.

Global risks arise from the long- or short-term release of large quantities of CO₂ back to the atmosphere, potentially reducing, if not negating altogether, the benefits of CO₂ sequestration. The consequences of CO₂ release back to the atmosphere are dependent on the volume of CO₂ released, emission rates, and ambient atmospheric CO₂ concentration at the time of the release.

In the near term, the risk of global impact associated with CO₂ storage is much smaller than risks of local impact, given the limited volume of CO₂ currently being stored. At this time, the permanence of geological storage has not been verified. Industrial operations such as the Weyburn and Sleipner projects, as well as small-scale demonstration and bench-scale projects, will help to provide a better understanding of the geochemical, hydrological, and geophysical interactions between the CO₂ and the storage formation, providing knowledge needed to more adequately assess both local and global environmental, health, and safety risks.

Table 2. Summary of Local Risks of CO₂ Migration out of the Storage Formation (Vendrig et al., 2003)

Media and Background CO ₂ Concentration	Consequences of Exposure Levels		
	Severe	Moderate	Low
Air (370 ppm)	Lethal, habitat loss (>10%)	Injuries (>5%)	Discomfort (>1%)
Buildings (370 ppm)	Injury, evacuation (>5%)	Irritation, discomfort (>2%)	Noticeable, no harm (>1%)
Groundwater (0.2%)	Acidity, well corrosion, irrigation loss (>6%)	Mild acidity and corrosion (>2%)	Elevated, low acidity, without significant impacts (>0.2%)
Surface Water (0.022%)	Acidity, CO ₂ mass release, fish kills (>2%)	Higher acidity, mild toxicity effect on irrigation (>1%)	Elevated, low acidity with no significant impacts (>0.022%)
Soils (1%–2%)	Low pH, tree kills, animal deaths (>8%)	Moderate acidity, tree/crop/soil cover loss (>3%)	Mild suppression in pH with no significant impacts (>2%)

Operational Risks

The capture, processing, transportation, and injection of CO₂ are proven practices with well-known risks and established risk management strategies. The most noted operational risks of CO₂ sequestration deal with pipeline or well failure, covering pinhole-size leaks, and catastrophic pipeline or well blowouts. Potential hazards of engineered systems can include failures caused by corrosion, vibration, external impact, operator error, inadequate maintenance, or equipment degradation (Vendrig et al., 2003). Engineering controls and specifications for transportation, storage containers, pipelines, and well construction and operation cannot eliminate all risks, but can greatly limit the likelihood of catastrophic failures.

Pipelines

Currently, about 2000 miles of CO₂ transmission pipelines are in operation in the United States, many of which have been in use for the last 20 years, transporting CO₂ as a supercritical or

dense-phase fluid (Gale and Davison, 2001). Since 1968, there have been 12 reported accidents, with no injuries and no fatalities (U.S. DOT, 2004b). Causes of accidents included a failed weld, corrosion, failure of control or relief equipment, and failure of other components.

Several unique properties of supercritical CO₂ are taken into account in pipeline design and construction, including the following (Gale and Davison, 2001):

- Reactive with water (reaction of CO₂ or other contaminants in the gas stream, including sulfur dioxide, with water will create a corrosive mixture [Kovscek, 2002]).
- Incompatible with some petroleum-based and synthetic lubricants.
- Incompatible with some elastomer sealing materials.
- Has poor lubricating properties.

- Transmission at supercritical conditions can result in brittle fracture and ductile fracture propagation.
- Dramatic cooling during decompression.

In addition to manufacturing standards placed on pipeline materials to prevent damage due to corrosion, safety regulations for pipeline construction include the implementation of an automatic pressure control system to monitor volumetric flow and pressure and block valves placed regularly along the length of the pipeline to minimize the risk of inadvertent release. Fracture arresters are also commonly used to limit the extent of a fracture along the length of the pipeline in the event of blowout. Unlike natural gas, CO₂ is neither flammable nor explosive. However, because it has a higher density than air, there is risk of elevated levels of CO₂ collecting in low-lying areas and poorly ventilated spaces in the vicinity of the leak resulting in an asphyxiation hazard. In open areas, CO₂ typically will quickly dissipate in the air, returning to safe concentrations. The rate of dissipation, however, will depend on the nature of the release, topography, and weather conditions.

Wells

Injection wells along with poorly plugged and abandoned wells may pose the greatest operational risk for loss of CO₂. Damage to wells can occur when they are operated at pressures exceeding the pressure ratings of the materials or when construction materials are incompatible with injected fluids, resulting in corrosion. Additional risks of leakage arise as a result of improper or partial plugging of wells, migration through abandoned wells that have not been identified, poor well construction, and improper deployment of shutoff capability and pressure-monitoring systems. Operator error can also result in

leakage; however, such occurrences can be avoided by following safe working and operating practices. The risk of catastrophic release from well blowout either inside or outside the casing of an injection well when high CO₂ pressure has built up in the injection reservoir is manageable with proper well construction, safety devices, and monitoring (Holloway, 2002).

While operational risks associated with sequestration are well understood and can be effectively managed, they still pose ecological, environmental, health, and safety concerns. The highest risk of human and environmental exposure will be in areas near injection, monitoring, production, plugged, and abandoned wells; surface facilities where CO₂ is recycled for enhanced oil recovery (EOR) operations; CO₂ transmission pipelines or transportation vessels; low-lying areas; underground construction including abandoned mine shafts; and other confined spaces above the injection plume or near engineered structures where leaks may occur.

Risks are not limited to the injection phase of a sequestration project. Because of the limited lifetime of construction materials, without proper monitoring and mitigation strategies, risks of well blowout may be of greater concern in the postabandonment phase of the project. In addition, there is significant concern about the risks to future human intervention (i.e., future drilling activities, redevelopment of an oil reservoir, and inadvertent or inadequately planned reentry). Regulatory safeguards will be required to ensure the long-term safe storage of CO₂.

In Situ Risks: Pathways of CO₂ Migration

Unlike operational risks, in situ risks arising from subsurface migration of CO₂ are far less defined and understood. In order to ensure safe and effective long-term storage of CO₂, thorough investigation of

the chemical and physical properties of the local geology as well as geochemical, geophysical, and hydrogeological interactions with CO₂ injection is needed. Pathways of migration include direct and indirect losses of CO₂ to the atmosphere from the subsurface through fractures or faults in the confining caprock; natural or induced seismic events; water movement; vegetation; and poorly constructed or sealed injection, monitoring, or production wells. In addition to direct and indirect losses to the atmosphere, transformation within the geological reservoir, including mineralization and demineralization, can occur.

Direct Release to the Atmosphere

Migration of CO₂ may occur laterally and updip within the reservoir formation itself or vertically through the confining sealing formations, driven by diffusion, buoyancy, and regional hydraulic gradients (Savage et al., 2003). Pathways for direct CO₂ release to the atmosphere include permeable strata; faults and fractures in the caprock or confining layer; natural or induced seismic events; and degrading, poorly constructed, or inadequately sealed wells. Relevant concerns regarding the safe and effective storage of CO₂ and potential for migration through the subsurface include both risks of large catastrophic release and slow release to the surface and atmosphere. The most commonly noted example of a catastrophic release of CO₂ is the 1986 limnic eruption from Lake Nyos, a crater lake in the volcanic region of Cameroon. The Lake Nyos release followed a slow buildup of CO₂ at the bottom of a stably stratified lake that was abruptly overturned as the CO₂ saturation level was reached. The explosive release caused more than 1700 human fatalities up to 25 km away, in addition to killing livestock and vegetation in its path. The impact of the eruption was magnified by the topography of the region, which allowed lethal concentrations of CO₂ to roll through the low-lying valley with limited dispersion.

While it is important to understand the cause and effect of a catastrophic event such as the eruption at Lake Nyos, it must also be understood that the conditions that must exist to cause a limnic eruption are not present with geological storage of CO₂. Catastrophic release from a storage reservoir is highly unlikely and can be mitigated through operational safeguards and monitoring.

Based on experience with EOR, natural gas storage, and naturally existing CO₂ reservoirs, the probability of diffuse leakage of CO₂ through poorly sealed or constructed wells or open faults is greater than catastrophic release due to well blowout or induced seismic events. The slow venting of CO₂ to the surface raises concerns for local ecological health and safety as well as global impacts, with particular concern over the difficulty in detecting small releases. The environmental effects of diffuse CO₂ leakage have been observed at Mammoth Mountain, California. The volcanic outgassing in this region has resulted in extensive tree kills (Farrar et al., 1995). From a local health and safety standpoint, the greatest risks will be in areas of dense population, topographical depressions, and poorly ventilated spaces near operating or abandoned wells or open faults. From a global perspective, diffuse leakage, if widespread, has the potential to impede attempts to control global climate change.

Natural and Induced Seismicity

Injection of large volumes of fluid can increase reservoir pressure, displace reservoir fluids, and induce seismic events. While Wesson and Nicholas (1987) noted that deep-well injection typically triggers activity in seismically unstable areas with a history of faulting or earthquakes, the unique properties of supercritical CO₂ may increase the potential for induced seismic activity in stable formations. Processes involved in the triggering of seismic activity may include transfer of stress to a weaker

fault, hydraulic fracture, contraction of rocks due to the extraction of fluids, subsidence due to the saturation of a rock formation, mineral precipitation along a fault, dissolution of minerals precipitated along a fault, and density-driven stress loading (Sminchak and Gupta, 2001). Induced seismic activity may be prevented through proper siting, installation, operation, and monitoring.

Migration to Overlying Freshwater Sources

The migration of CO₂ from the storage reservoir to a freshwater aquifer or surface waters poses potential risks to water quality and local biota. The effects of CO₂ on groundwater and surface waters are dependent on the volume of CO₂ released, the time period over which the release occurs, the buffer capacity of the water, and the mixing rate. The accumulation of CO₂ eventually increases the acidity of the water through formation of carbonic acid, leading to impairment of biological function and dissolution and/or mobilization of metals and organic compounds naturally sorbed or precipitated on sediments or aquifer minerals. Heavy metals such as Fe, Mn, Cu, Pb, and As all may be mobilized at low pH. In addition, at low pH, reaction with alkaline materials such as limestone may lead to increases in soil and groundwater salinity.

Migration of CO₂ to overlying groundwater sources is most likely to occur along the injection well if not properly constructed or through poorly constructed or deteriorating wells that reach the storage reservoir. While proper siting, well construction, and well closure will minimize the risk of CO₂ migration to water supplies, chemical analysis of surface waters and groundwater may be required to identify if leakage from the storage formation has occurred.

Injection-induced displacement of reservoir fluid or gas to overlying freshwater sources

also poses concern for water quality and ecological health and safety. Displaced fluids or gases are likely to follow the same migration pathways as CO₂. Again, proper site characterization, construction, operation, and monitoring will limit potential risks.

Transformation

The unique properties of CO₂ in its supercritical state allow it to act as a solvent with the capability to dissolve and weaken the rocks in the injection formation. Dissolution of rock minerals and precipitation of new minerals in the caprock may result in increased or decreased permeability of the confining layer. An increase in permeability may weaken the stratigraphic seal, increasing the risk of leakage from the storage reservoir. Likewise, a decrease in permeability also has the potential to increase risk of migration if precipitants exert a force in the pore spaces great enough to cause fracturing of the caprock. Alternatively, the dissolution of CO₂ may provide the primary means for long-term storage via solubility trapping (as carbonate aqueous species) and mineral trapping (as carbonate minerals) (Knauss et al., 2001; Vine, 2003). While a great deal of information can be garnered from the investigation of naturally occurring CO₂ reservoirs, a significant research effort is required to fully understand the reaction processes involved in long-term storage.

Additional Concern for Ecological and Environmental Impacts

From a conceptual point of view, it has been argued that while large-scale utilization of CO₂ sequestration has the potential to reduce CO₂ emissions, effects could be weakened if sequestration also drives increased energy production from fossil fuels. The primary concern with such a scenario is that with increased fossil fuel utilization, large-scale leakage from storage reservoirs could drive atmospheric CO₂ concentrations to even higher levels. While

this is a reasonable concern, it is believed that the risk created by increased fossil fuel use can be managed and mitigated by an appropriate regulatory regime and systems management approach with proper accounting (Heinrich et al., 2004). Thorough site characterization, with a focus on the integrity of the caprock or confining layer and long-term stability of the formation, is necessary to identify reservoirs that will provide long-term safe storage of CO₂.

Of additional concern is the potential for increased waste generation in CO₂ capture and separation processes. Today's amine solvent separation process creates wastes that pose risks to environmental health and safety if not managed and disposed of properly. Speculative estimates suggest that CO₂ capture at a 500-MW gas-fired power station could produce approximately 2000 metric tons/year of sludge from decomposed amines and about 10 metric tons/year of carryover in the flue gas (Davidson et al., 2001).

Lessons Learned from Natural and Industrial Analogs

There is no shortage of natural and industrial analogs to CO₂ sequestration from which lessons can be learned for assessing and mitigating risks. Benson et al. (2002) provide a comprehensive review of the following analogs to CO₂ sequestration in terms of associated risks, environmental and human health effects, monitoring and mitigation strategies, and regulatory frameworks, where applicable:

- Natural analogs
 - Natural accumulations of CO₂ in the subsurface (CO₂ reservoirs).
 - Natural subsurface release of CO₂ (i.e., volcanic eruptions, limnic releases, hydrothermal vents, diffuse venting).
- Industrial analogs
 - Disposal of industrial liquid waste in deep geological formations.
 - Underground natural gas storage.
 - Nuclear waste disposal.
 - Industrial handling of CO₂.

Several of these analogs will be discussed further in the Regulatory Framework section.

It is essential that potential risks and the probability of adverse impact to the environment or human health and safety resulting from CO₂ sequestration be clearly identified. Full risk assessment and strategies for mitigation should failure occur are necessary to ensure both the near-term and long-term safety of CO₂ capture and storage projects.

What is known to date concerning the risks of geological CO₂ sequestration includes the following:

- CO₂ can be safely stored in geological formations over long periods of time as observed with naturally existing CO₂ reservoirs.
- Environmental and ecological health effects are well understood.
- The largest risks of CO₂ capture and storage have been identified.
- Local hazards are generally more dependent on the nature of the release than the size of the release.
- CO₂ poses no health and safety risk at low concentrations.
- CO₂ is not flammable or explosive, but does react with water.
- CO₂ is denser than air and has the potential to pool in low-lying areas or poorly ventilated spaces.

ECOLOGICAL AND ENVIRONMENTAL IMPACTS OF TERRESTRIAL SEQUESTRATION

Unlike geological carbon storage, terrestrial sequestration, as conducted today, poses no risk to human health and safety resultant of direct CO₂ exposure. While local and global risks may arise with terrestrial sequestration, a majority of terrestrial sequestration methods will actually provide added benefits to the environment (i.e., improvement in soil health, reduced erosion, enhancement of wildlife habitat, etc.). The few risks that may exist in terrestrial sequestration projects are generally associated with human- or nature-induced forest fires; the use of nutrient amendments, pesticides, or herbicides to promote biomass growth; and changes in land management practices, which negate sequestration gains.

The primary environmental concern regarding terrestrial sequestration is the global risk of large-scale release of CO₂ from plant or soil systems subsequent to sequestration activities. In order for terrestrial sequestration to be an effective means for mitigating elevated levels of atmospheric carbon, it must be successful over very large timescales. One obvious threat to sequestration success is forest fires. While suppression, prevention, and management techniques may be employed to limit large-scale burning, forest fires are an integral part of nature's ecosystems and are, therefore, inevitable. Management techniques, which encourage small-scale burning or the clearing of dead growth as to reduce the fuel available for a fire, may limit the amount of CO₂ released during any single event. In addition, harvesting trees in an environmentally sound manner to produce durable wood products may increase long-term carbon sequestration potential.

It is important that management strategies for sequestering carbon are planned with

the intent for long-term storage and that sequestration activities in one area do not cause deleterious use of land in another. In order to ensure long-term benefit, it is also important that any changes in land management practices following implementation of sequestration activities do not upset sequestration gains. Given the long-term variability and uncertainty in the agricultural market, realizing long-term benefits of the land management practices we adopt today may be challenging. There are currently no standard methods for addressing duration or permanence in sequestration projects. Proposed ideas for addressing this important issue include the use of insurance mechanisms, diversification of projects, issuance of temporary credits, and discounting credits as sequestration efforts change.

Adverse environmental impacts of carbon sequestration practices at the local level may result from field application of chemicals to promote biomass growth. Unintended consequences of fertilizers, herbicides, and pesticides may include nutrient loading in rivers and streams, contamination of surface waters or groundwaters, and negative impact on soil health and terrestrial and aquatic ecology. These risks are not only familiar but also largely manageable. It is important that any sequestration plan that requires the use of chemical amendments be carefully managed to prevent or limit any negative impact from their use.

MEASUREMENT, MITIGATION, AND VERIFICATION OF GEOLOGICAL CARBON CAPTURE AND STORAGE

To ensure that the geological storage of CO₂ is effective and poses no unacceptable environmental risk, close MM&V will be required through all phases of CO₂ sequestration, including capture and separation, transportation, injection, and long-term storage. MM&V of CO₂ sequestration will be effective only if it can

accurately measure and account for CO₂ coming into and leaving the storage reservoir; is cost-effective and reliable over long periods of time; and is relatively easy to operate, with emphasis on remote operation.

If sequestration is to provide a primary method for reducing atmospheric concentrations of CO₂, MM&V will be required as part of the permitting process to ensure that any single sequestration project is successful as a CO₂ control technology and poses no adverse effect to environmental health and safety. Prior to broad-scale implementation of CO₂ storage, MM&V techniques must be successfully demonstrated for assessing the storage capacity and integrity of a given storage reservoir; quantitatively measuring the amount of CO₂ effectively stored in the formation; monitoring for leaks or deterioration of storage integrity; monitoring geological, geochemical, and hydrological transformations; verifying that CO₂ is being effectively stored and causes no local or global risks; and mitigating the negative effects of CO₂ release should sequestration mechanisms fail.

Elements of MM&V

The implementation of MM&V strategies serves several purposes, including 1) protecting worker health and safety; 2) ensuring environmental and ecological safety; 3) verifying safe and effective storage, including providing assurances of carbon credits or transactions in a carbon-trading market; 4) tracking plume migration; 5) providing early warning for failure; and 6) confirming model predictions. The primary elements associated with the MM&V of geological carbon capture and storage can be divided into two categories: 1) the careful monitoring of engineered systems and 2) the monitoring of migration of CO₂ within, and out of, the primary storage reservoir. The monitoring of engineered

systems may include, but not be limited to, the following:

- Capture and separation technology system integrity.
- Gas composition.
- Pipeline integrity pressures and flow rates.
- Protection devices and safeguards.
- Injection well integrity.
- Integrity of monitoring wells, production wells, and abandoned wells.
- Wellhead pressures.
- Injection volume and flow rate.
- Leakage around the injection well.
- Gas collection and recycling.
- Leakage into or through engineered structures in connection with, or in the area of, the storage reservoir (i.e., wells, mine shafts, basements).

MM&V to assess the effectiveness and safety of the storage reservoir may include:

- Geological characterization and assessment prior to injection for establishing a baseline for subsequent monitoring.
- Location of faults and weaknesses in the caprock of the primary storage reservoir that may serve as pathways for migration.
- Location of potential underground sources of drinking water.
- Groundwater movement.

- CO₂ plume location and migration.
- Concentration and density of CO₂ in the reservoir.
- Reservoir pressure.
- Effective use of available reservoir storage volume.
- Geophysical and geochemical interactions between CO₂, reservoir fluids, reservoir minerals, and caprock.
- Seismic activity.
- Groundwater quality.
- Surface water quality.
- Soil and vegetation condition.
- CO₂ gas concentration in the vadose zone and soils.
- Health of shallow subsurface and surface ecosystems.
- CO₂ concentrations and flux at the ground surface.
- Topographical features and poorly ventilated areas that may collect elevated concentrations of CO₂.
- Open faults.

Effective MM&V will accurately account for CO₂ entering and leaving the storage reservoir and adequately identify sources of leakage so that mitigation and remediation strategies can be effectively implemented.

MM&V Methods

No standard procedure or set of technologies has been developed or proven

for the explicit purpose of monitoring the effectiveness and safety of CO₂ capture and geological storage. However, numerous well-established procedures and monitoring technologies applicable to CO₂ sequestration may be adapted from oil and gas exploration and production, hazardous and nonhazardous industrial waste injection, acid gas injection, nuclear waste storage, natural gas storage, groundwater monitoring, and food preservation and beverage industries.

Variability in geological storage formations, injection volumes, and gas compositions will complicate the development of a broad-scale MM&V strategy. For this reason, there may be value in taking a tailored approach to monitoring that accounts for the unique conditions and risks at each storage site (Benson and Myer, 2002). For example, in a well-characterized depleted oil reservoir with well-defined caprock, focus may be placed on the most likely pathways of leakage (i.e., injection well or abandoned wells), while in a poorly characterized brine formation, it may be of greater value to concentrate on plume tracking and geochemical and geophysical interactions. One might also look at the health and safety aspects of the project and determine that more thorough investigation and implementation of protections is needed in highly populated areas or topographical regions that are more apt to collect elevated concentrations of CO₂ than in areas where leakage is less likely to pose a human health hazard or concern.

Table 3 provides a summary of monitoring practices that could be applied to CO₂ capture and storage activities. Further description is provided in the text that follows.

Geophysical Monitoring Practices: Seismic, Electrical, and Gravity Measurement

Decades of experience and development of subsurface monitoring techniques in the oil and gas industry provide a strong foundation for MM&V of geological CO₂ sequestration.

Table 3. Monitoring Methods Applicable to Geological CO₂ Sequestration (Benson and Myer, 2002)

Parameter	Monitoring Approaches/Technology
CO ₂ Plume Location	<ul style="list-style-type: none"> • 2- and 3-D time-lapse seismic reflection surveys. • Vertical seismic profiling (VSP) and cross-wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Satellite imagery of vegetation changes (hyperspectral analysis) • Gravimetric surveys • Reservoir pressure monitoring • Wellhead and formation fluid sampling • Natural and introduced tracers • Geochemical changes identified in observation or production wells
Early Warning of Storage Reservoir Failure	<ul style="list-style-type: none"> • 2- and 3-D time-lapse seismic reflection surveys • VSP and cross-wellbore seismic surveys • Satellite imagery of land surface deformation • Injection well and reservoir pressure monitoring • Pressure and geochemical monitoring in overlying formations • Microseismicity or passive seismic monitoring
CO ₂ Concentrations and Flux at Ground Surface	<ul style="list-style-type: none"> • Real-time infrared-based detectors • Air sampling and analysis using gas chromatography or mass spectrometry • Eddy flux towers • Monitoring for natural and introduced tracers • Hyperspectral imagery to detect changes in vegetation
Injection Well Condition, Flow Rates, and Pressures	<ul style="list-style-type: none"> • 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 flowmeters • Well integrity tests • Surface CO₂ concentrations near injection wells
Pipeline Integrity, Volumetric Flow, and Pressure	<ul style="list-style-type: none"> • Hydrostatic testing • Close interval surveys • Ultrasonic evaluation • Pressure control systems and Supervisory Control and Data Acquisition (SCADA)

Continued...

Table 3. Monitoring Methods Applicable to Geological CO₂ Sequestration (Benson and Myer, 2002) (continued)

Solubility and Mineral Trapping	<ul style="list-style-type: none"> • Formation fluid sampling using wellhead or downhole samples; analysis of CO₂, major ion chemistry and isotopes • Monitoring for natural and introduced tracers including partitioning tracers
Leakage Through Faults and Fractures	<ul style="list-style-type: none"> • 2- and 3-D time-lapse seismic reflection surveys • VSP and cross-wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Reservoir and aquifer pressure monitoring • Microseismicity or passive seismic monitoring • Groundwater and vadose zone sampling • Hyperspectral imagery to detect changes in vegetation
Groundwater Quality	<ul style="list-style-type: none"> • Groundwater sampling and geochemical analysis from drinking water or monitoring wells • Natural and introduced tracers
CO ₂ Concentrations in Vadose Zone and Soil	<ul style="list-style-type: none"> • Soil gas surveys and gas composition analysis • Vadose zone sampling wells and gas composition analysis • Hyperspectral imagery to detect changes in vegetation
Ecosystem Impacts	<ul style="list-style-type: none"> • Soil gas surveys • Soil sampling • Direct observation of biota • Hyperspectral imagery to detect changes in vegetation

Monitoring practices developed for oil and gas exploration and production include long-established surface seismic, electrical and gravity measurements, and more recent advances in higher-resolution cross-well, single-well, and surface-to-borehole seismic; cross-well electromagnetic; and electrical resistance tomography (ERT).

Geophysical techniques rely on the chemical and physical properties of the geological formation to monitor the movement of reservoir fluids in the subsurface. Both seismic and electrical properties depend on the mineralogical composition of the rock, porosity, formation fluid, and in situ stress state (Myer, 2001). The effectiveness of such techniques depends on many factors, including the magnitude of the change in

the measured geophysical property produced by CO₂, the inherent resolution of the technique, and the configuration in which the measurement is deployed (Benson and Myer, 2002). Because geophysical measurements only provide an indirect, nonunique indication of the presence of CO₂, the use of multiple techniques is required to reduce ambiguity in interpretation of results (Hoversten and Myer, 2000).

Today, surface measurements can provide more economical spatial coverage of a large formation than the higher-resolution subsurface techniques. While numerous activities are being conducted to further develop and demonstrate advanced technologies for use in monitoring CO₂ sequestration, Myer et al. (2002) note that

high-resolution wellbore and interwell (cross-well) geophysics are either limited to sampling near the wellbore or too expensive for monitoring the entire reservoir. In addition to geophysical measurements, researchers will likely look to hydrologic and geochemical measurements to provide additional information about the distribution of the CO₂ in the interwell region.

Seismic Surveying Methods

Seismic methods rely on the relationship between seismic velocities and the density and elastic stiffness of the formation (and its contained fluids) (Myer, 2000). Because CO₂ is less dense and more compressible than brine and oil, seismic methods may be useful in both deep brine and oil reservoirs. Injection of CO₂ into a geological formation has been shown to alter the bulk density, the Poisson's ratio, and the seismic velocity of the p-wave and the s-wave—phenomena that combine to alter the reflected seismic wave's amplitude and travel time (White et al., 2003).

Surface Seismic

Conventional seismic surveying involves the utilization of a controlled source of seismic energy (i.e., dynamite, air guns, vibrators); illumination of a subsurface target area with downward-propagating waves; reflection, refraction, and diffraction of the seismic waves by subsurface heterogeneities; and detection of the backscattered seismic energy on seismometers (geophones) spread along a linear or areal array on the Earth's surface (Scales, 1994). 3-D seismic surveying is commonly used in the oil and gas industry. Performing 3-D seismic surveys before, during, and after injection can provide a time-lapse picture of the movement of fluids in the subsurface (referred to as 4-D seismic, with time being the added dimension). 4-D seismic surveys are being demonstrated in the PCOR Partnership region for EOR operations at the Weyburn Oil Field in Saskatchewan.

Passive Seismic

Passive seismic is a surface seismic surveying technique that relies on naturally occurring microseismic events, including fluid front movement in the reservoir, as sources of seismic energy (MicroSeismic, Inc., 2004).

Surface-to-Borehole Seismic

VSP is a seismic technique that measures acoustic waves between a well bore and the surface. VSP is higher in resolution than surface seismic techniques and provides a direct correlation between subsurface stratigraphy and seismic reflections measured at the surface.

Cross-Well Seismic

Cross-well seismic technology provides high-definition reservoir characterization between boreholes by recording the seismic waves transmitted between a single-source well and one or more receiver wells (Salehi and Siegfried, 1998; HDSeis Services, 2004).

Single-Well Seismic

Single-well acquisition provides high-definition subsurface characterization in the vicinity of a single borehole by combining the downhole receivers and downhole source in the same borehole (HDSeis Services, 2004).

Multicomponent Seismic

Nine-component (9-C) seismology offers the best technology possible for monitoring both lateral and vertical sweep in EOR operations. The different components have different sensitivity to fluid saturation, pressure, and reservoir properties (Terrell et al., 2002). For instance, fractures can introduce seismic anisotropy to the reservoir, causing two shear modes to propagate with different velocities. The amplitudes of the split shear waves can then be used to observe and monitor production processes and provide a critical parameter for estimating fracture density (Davis, 2001). The Weyburn Oil Field is the

site of experimental monitoring designed to enhance the resolution of multicomponent seismic data in monitoring production processes. Experimental results in the Weyburn Field show that sensitivity to monitoring with p-wave amplitudes and s-wave amplitudes varies according to formation properties (Terrell et al., 2002).

Electrical and Electromagnetic Surveying Methods

Electrical surveying techniques measure electrical resistivity or conductivity of different materials to low-frequency electrical current and electromagnetic fields and waves. Since porosity, pore fluid conductivity, saturation, and temperature all influence electrical conductivity, it has a more direct relationship to reservoir fluid properties than do seismic parameters (Wilt et al., 1995a). The presence of CO₂ in a geological formation alters the electrical resistivity of the geological formation (White et al., 2003) making CO₂ “visible.”

Electrical Resistance Tomography (ERT)

ERT creates 2-D or 3-D visualizations of the subsurface by generating a low-frequency electrical current in the ground (using electrodes) and measuring the potential distribution that results from the current flowing in the conductive subsurface. ERT can be used during injection to obtain a series of images that shows a relatively rapid change in electrical resistivity (U.S. Department of Energy, 2000). Research is under way at Lawrence Livermore National Laboratory (LLNL) to employ metallic well casings as long electrodes, providing a noninvasive technique to monitor CO₂ sequestration utilizing existing subsurface infrastructure (Newmark et al., 2001a).

Electromagnetic Tomography

Electromagnetic tomography (EMT) measures the electrical resistivity of different subsurface materials to electromagnetic fields and waves. Cross-well electromagnetic (EM) induction allows

for the mapping of subsurface resistivity at multiple frequencies between wells. In EMT, inductance is measured using an alternating current (AC) magnetic field (vs. electric field) to excite the subsurface. EMT techniques are typically used where the material distribution can be characterized by either high electrical conductivity or ferromagnetic behavior (Peyton et al., 1999).

LLNL is currently involved in a long-term study using time-lapse multiple frequency EM characterization at an EOR site in Lost Hills, California (Kirkendall and Roberts, 2001). EM techniques are sensitive to rock pore fluids within the subsurface, which makes them the ideal method for addressing the problems of EOR in a heavy-oil environment. The high sensitivity of EM energy to these physical processes, as well as recent advances in computational ability, inversion code resolution, and field instrumentation, make borehole EM techniques an important tool for subsurface imaging problems. In CO₂ sequestration, the high pressure of injection forces the CO₂ to remain in a dense-phase state during injection. However, after delivery to the subsurface, there is the potential, based on reservoir conditions, that a volumetric increase of the CO₂ would force CO₂ to the vapor state. Based on initial model calculations, it is expected that a large contrast will exist between the formation water and petroleum-CO₂ but a small contrast between CO₂ and petroleum because of similar inherent electrical conductivity. Resolution of the small contrast will be possible with laboratory analysis and with improved gas interpretation techniques.

Because both seismic and electrical properties depend on the mineralogical composition of the rock, porosity, fluid content, and in situ stress state, laboratory measurements are required for geophysical survey interpretation (Myer, 2001).

Probably the greatest shortcoming in the geophysical surveying methods available today lies in the difficulty of quantitatively assessing CO₂ saturation within, and its rate of leakage from, the storage reservoir. While research is under way to address the issue of quantifying CO₂ saturation with geophysical surveying techniques, the rate of leakage will unlikely be addressed by geophysical techniques alone.

Analysis of CO₂ Flow Rates and Injection and Formation Pressures

The measurement of CO₂ injection rates and pressures is a routine practice in EOR operations, and current technologies are more than adequate for application in providing quantitative monitoring of CO₂ sequestration. Flow rate is typically measured with orifice meters or other differential-producing devices that relate the pressure drop across the device to the flow rate. Injection pressures can be measured both at the wellhead and in the formation by a variety of pressure sensors, including piezoelectric transducers, strain gauges, diaphragms, and capacitance gauges, all of which are applicable to monitoring CO₂ injection (Benson and Myer, 2002).

Analysis of Well Logs

A variety of well-logging techniques including caliper and sonic logging, resistivity, electrical conductivity, self-potential (SP), induced polarization, magnetic susceptibility, natural gamma logging, and neutron porosity logging are commonly employed in oil and gas exploration and production to assess well condition, formation mineralogy, permeability, porosity, pore fluid composition, and more (Prame et al., 2002). CO₂ sequestration projects will likely rely heavily on existing well logs for initial site characterization and site selection. Collection of additional well logs throughout the life of the project will be used to evaluate CO₂, including assessment of pressure and fluid in

overlying formations, assessment of leakage potential, and detection of leakage through the borehole. The primary drawbacks of well-logging techniques for formation evaluation and CO₂ sequestration monitoring are 1) limitations in penetrating capability, ultimately limiting monitoring to the area near the wellbore and 2) increased risk of leakage because of the intrusive nature of the technique.

Direct Measurement of CO₂

Several monitoring methods providing direct measurement of CO₂ in soils, water, and air may be used for the detection of leakage from the primary storage reservoir or engineered systems. Continuous sensor monitoring technologies are currently used in numerous industries that handle CO₂. Standard technologies include infrared (IR) gas analyzers, which are typically compact and portable for occupational use. For additional assurance, safety protocols may also require periodic use of gas-sampling bags and gas chromatography.

Simple, portable IR detectors are also available for field use. The U.S. Geological Survey (USGS) has successfully measured CO₂ soil flux at the volcanically active Mammoth Mountain site using LI-COR IR gas analyzers (U.S. Geological Survey, 2000). While this surveying technique is capable of detecting low CO₂ emission rates, it is limited by the spatial extent of the field, potentially requiring hundreds or thousands of collection points to adequately assess broad-coverage leakage. Seasonal changes, including soil moisture, plant respiration, and microbial activity, can greatly impact measured CO₂ at the ground surface. It is, therefore, advantageous to monitor seasonal CO₂ soil gas fluctuation prior to CO₂ injection and through the lifetime of the project as a possible verification of CO₂ sequestration.

Atmospheric detection of CO₂ is also complicated by high ambient and natural

CO₂ fluxes, making it difficult to isolate small leaks from the subsurface. Eddy flux correlation measurements (ECOR), currently used by biogeochemists studying ecosystem-scale carbon cycling to reconstruct average CO₂ flux over large areas, may assist in detecting reservoir leakage (Benson et al., 2002). Other methods of atmospheric monitoring may include remote sensing techniques via satellite or low-flying aircraft surveying. Remote sensing techniques currently under investigation for CO₂ detection include light detection and ranging (Lidar), differential absorption Lidar (DIAL), and scanning airborne laser technology. Because of the long path length through the atmosphere and inherent variability of atmospheric CO₂, remote sensing is not applicable to monitoring diffuse surface leaks of CO₂.

Additional soil gases may also provide indication of CO₂ leakage or instability of the storage reservoir. O₂, CH₄, radon (²²²Rn), thoron (Tn, or radioisotope ²²⁰Rn), helium, and other gases are all being monitored at the Weyburn Field in Saskatchewan (Parsons et al., 2004).

Geochemical Methods and Tracers

Geochemical methods may be utilized to provide information regarding both the migration of CO₂ within a storage reservoir and chemical transformations as it reacts with reservoir fluids and rocks.

Geochemical fluid sampling can be conducted from the formation with a downhole sampler or at the wellhead if the well is pumped. Downhole-sampling methods provide samples that are more representative of the formation, however, at a considerably greater cost than wellhead sampling. Standard analytical techniques are available for analyzing fluid samples including analysis of major ions, stable isotopes, pH, alkalinity, and gases. Interpretation of analysis is not as straightforward and will require considerable investigation as large-scale

implementation of CO₂ sequestration projects moves forward.

The use of natural and/or introduced chemical tracers, sensitive to the hydrodynamic conductivity and connectivity of the formation as well as chemical processes, may provide additional information on the fate and transport of CO₂ in the subsurface. Tracers may be useful in estimating CO₂ residence time and storage mechanisms, evaluating process optimization, and assessing potential leakage. Chemical tracers under investigation for CO₂ sequestration monitoring include isotopes and noble gases associated with the injected CO₂ as well as introduced isotopes, SF₆, and perfluorocarbons (Cole and Phelps, 2003). As with other geochemical methods of investigation, interpretation of sample analyses is not simple and will require considerable investigation if tracers are to be used successfully in understanding both the migration and chemical transformation of CO₂.

Land Surface Deformation and Spectral Imaging

Methods for assessing land surface deformation, including tiltmeters and aircraft or satellite-based technologies such as InSAR (interferometric synthetic aperture radar) may prove to be effective for identifying potential leakage pathways (i.e., open faults and injection-induced ground surface changes). In addition, visual assessments or remote spectral imaging of changes in CO₂-sensitive biomass may aid in recognizing areas where leakage has already occurred. In addition to surface sampling, remote spectral imaging has been successfully employed at Mammoth Mountain, California, to detect tree killings from volcanic outgassing of CO₂.

Pipeline Monitoring and Testing

Methods for pipeline inspection and testing have been adequately developed and

proven effective for the safe transport of CO₂. SCADA systems are in place along current pipeline infrastructure to remotely monitor such parameters as volumetric flow and pressures and provide rapid response in the event of pipeline failure or unsafe conditions. Inspections to assess pipeline integrity are conducted on a regular basis. Some of the techniques currently employed include hydrostatic testing, close interval potential, and direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) surveying, and ultrasonic inspection. New technologies, including advanced smart pigs, are being developed for application in CO₂ pipeline inspection. Dense-phase CO₂ penetrates current smart pig components, causing significant damage resulting from expansion upon decompression. Researchers are focusing on sealing materials that would prevent CO₂ penetration (Kinder Morgan, 2004).

Frequency of Monitoring

The frequency of monitoring required to ensure long-term environmental and ecological health and safety will likely vary by site according to identified risks and probability of environmental or ecological impact. The high level of MM&V required during site selection, injection, closure, and abandonment would most likely narrow in focus and frequency later in the storage process (postabandonment) as risks are better defined. The problem of identifying slow leakage over a long time frame is critical and will require further attention.

Modeling

Given the anticipated lifetime of a geological CO₂ sequestration project, modeling will be an essential tool for predicting the effectiveness of a storage reservoir hundreds of years after monitoring has ceased. In the near term, monitoring activities are not only necessary to ensure environmental health and safety, but are also imperative to

confirm that the project is performing as expected from predictive models. It is the latter that will provide assurance of the long-term global benefits expected from CO₂ sequestration.

Status of MM&V Technologies for Use in Monitoring CO₂

With increased focus on global climate change, CO₂ sequestration has gained international attention within both the research community and industry. The primary goals of today's research and demonstration projects are to gain a better understanding of the uncertainties associated with CO₂ capture and storage including long-term geophysical and geochemical interactions, subsurface migration, and leakage potential through the extensive evaluation and development of effective monitoring, mitigation, and long-term management strategies. The following information represents only a portion of the broad-scale research, development, and demonstration occurring today with respect to MM&V of geological CO₂ capture and storage. The purpose of this section is to provide a brief overview of selected projects to illustrate the magnitude of this effort.

Weyburn CO₂ Monitoring and Storage Project

The Petroleum Technology Research Centre (PTRC), in collaboration with EnCana Resources and with the support of the International Energy Agency Greenhouse Gas R&D Programme (IEA GHG), launched the IEA GHG Weyburn CO₂ Monitoring and Storage Project in July 2000. In September 2000, EnCana initiated the first phase of a CO₂ EOR scheme in 18 inverted 9-spot patterns, with the injection of 95 mmscfd of 95% pure CO₂.

A key objective of the Weyburn monitoring and storage project is to enhance the knowledge and understanding of EOR and CO₂ sequestration through development of monitoring and analytical methodologies.

Specific objectives include 1) testing and improving conventional geological-based simulator predictions of how the CO₂ flood will progress, 2) assessing the chemical reactions that form the predicted mechanisms for long-term storage of CO₂ within the reservoir, 3) observing the dynamic response of the reservoir to CO₂ flooding, 4) developing and demonstrating robust methods for monitoring the CO₂ flood, and 5) determining the distribution and security of the CO₂ within the reservoir (Wilson et al., 2004). The Weyburn monitoring program has included the utilization of extensive field production and analytical data, comprehensive geological modeling, geochemistry of production fluid and gases, assessment of geochemical impacts on the formation's CO₂ storage integrity and capacity, 3-D multicomponent time-lapse seismic monitoring, passive microseismic monitoring, and soil gas sampling (IEA GHG R&D Programme, 2004a; White, 2004). In addition, remote sensing data including air photos, topographic maps, and satellite images have been acquired to map surface lineaments and geomorphic anomalies in the project area (Whittaker et al., 2002).

4-D, high-resolution, multicomponent (9-C) seismology was designed to provide high-resolution time-lapse imaging over four CO₂ injection patterns in the heart of the first phase of the flood area. The objectives are to carry out dynamic reservoir characterization with a focus on anisotropy and also obtain time-lapse imaging of CO₂ advancement. New triaxial vibrators provided multicomponent sources to impart three orthogonal directions of ground motion for the seismic survey (Davis, 2001; Kendall et al., 2003; Jazwari, 2002; Terrell et al., 2002; Whittaker et al., 2002). The advantage of using multicomponent (9-C) seismic data is the ability to differentiate the fluids within the matrix and fracture systems as

well as within the different units of the reservoir.

Initial results taken in the fall of 2001 showed, for the most part, an orderly advance of the CO₂ into the reservoir, along the line of the horizontal injectors. However, like the 4-D multicomponent survey, there was some evidence of CO₂ fingering along suspected off-pattern fractures, signaling the possibility of early CO₂ breakthrough in some locations (Guoping, 2003). Results reported as of May 2004 indicate that monitoring methods are capable of clearly showing physical and chemical effects associated with CO₂ injection; geochemistry analysis has indicated good spatial correlation between chemical processes observed with the highest CO₂ injection volumes and seismic monitoring; and seismic methods have shown time and amplitude anomalies with no evidence for significant CO₂ migration from the reservoir (White, 2004).

Saline Aquifer CO₂ Storage (SACS) Monitoring Project, North Sea, Norway

The Sleipner project is the world's first commercial-scale CO₂ storage operation for mitigating climate change. Since 1996, nearly 1 million metric tons per year of CO₂ has been injected into the sands of the Utsira Formation (IEA GHG R&D Programme, 2004b). A 3-D seismic survey of the Sleipner Field conducted prior to injection provided important insight into the geology of the area immediately surrounding the injection site. Several techniques were considered for monitoring the fate and transport of CO₂ in the Sleipner Field. Ultimately, 3-D time-lapse surface seismic surveying was employed based on both technical and economic considerations. The utilization of a surface seismic survey avoided the high cost and risk of leakage associated with the construction of a monitoring well. A seismic feasibility study was conducted by modeling the expected seismic response before and after injection of CO₂. In the

Utsira Formation, CO₂ is highly compressible. Because the rock matrix in the formation is weak, the compressional velocity is also unusually sensitive to the compressibility of the fluid. Therefore, the presence of CO₂ induces a dramatic drop in the compressional wave velocity, leading to a clear change in seismic response (Arts et al., 2000, 2002; Torp and Gale, 2002). The first 3-D time-lapse seismic survey was conducted in 1999, 3 years after injection began, and qualitatively corroborated the results of the seismic modeling study.

Frio Brine Pilot Experiment, Texas

The Frio Brine pilot experiment was initiated in August 2002 in the brine-bearing Frio Formation near Houston, Texas. The experiment is designed to demonstrate the feasibility and safety of CO₂ injection into a brine formation through extensive monitoring and modeling of the injection of a small amount of CO₂ over a short period of time. Injection began on October 4, 2004, and lasted for a period of 9 days. The total volume of CO₂ injected was 1600 tons. Extensive methods are now being used to monitor the response both within the targeted sandstone bed and in an overlying thin sandstone. Prior to injection, baseline aqueous geochemistry, wireline logging, cross-well seismic, cross-well electromagnetic imaging, VSP, two-well hydrologic testing, and surface water and gas monitoring were completed (U.S. Department of Energy Techline, 2003). Injection performance evaluation will include monitoring cross-well breakthrough using a wireline reservoir simulation tool (RST) and gas and brine sampling; pressure buildup and falloff analysis collected in the injection and observation wells; monitoring CO₂ phases with natural and introduced noble gases, introduced perfluorocarbon (PFC) tracers, and the natural stable isotopic composition of carbon and oxygen; reactive transport modeling; assessment of

compartmentalization from production history; modeling of geophysical response; and geochemical modeling (Hovorka and Knox, 2002; Hovorka et al., 2004). Vertical seismic and cross-well seismic profiling will be repeated postinjection to characterize plume geometry. Wireline logging, aqueous and gas geochemistry, and surface monitoring will be repeated at regular intervals. Larger-scale follow-on testing is planned to determine the formation's capacity to store CO₂ and to identify any potential environmental impacts.

West Pearl Queen Field, New Mexico

Remote geophysical sensing tools are being applied before, during, and after injection of CO₂ in a depleted oil well in the West Pearl Queen Field of New Mexico. Monitoring techniques include surface-to-borehole surveys with vertical seismic profiling and surface reflection surveys to identify and, possibly, characterize formation changes as a consequence of CO₂ injection (Westrich et al., 2001).

Ohio River Valley CO₂ Storage Project, West Virginia

Drilling began in 2003 on a 10,000-foot well to evaluate underground rock layers in New Haven, West Virginia, as part of a U.S. Department of Energy (DOE) carbon sequestration research project now under way at the American Electric Power (AEP) Mountaineer Plant. Prior to drilling, a 2-D surface seismic survey was conducted. Borehole characterization included a suite of wireline borehole geophysical tools, core collection and analysis, brine analysis, and reservoir hydraulic testing (Gupta et al., 2004). The 18-month AEP study will determine whether the geology near the Mountaineer Plant is suitable for injection and long-term storage of CO₂ (U.S. Department of Energy Techline, 2003). Study findings will indicate whether rocks above possible disposal areas are stable and sufficiently free of interconnected

fractures to prevent the vertical migration of CO₂ (Battelle, 2003).

Texas Technical University

Texas Technical University is developing a well-logging technique based on the use of nuclear magnetic resonance (NMR) to characterize geological formations, including investigation of the integrity and quality of the reservoir seal (FRED, 2003). Since well logging using NMR does not require coring, it can be performed more quickly and efficiently (Klara et al., 2003).

GEO-SEQ Project

The GEO-SEQ project, sponsored by DOE's National Energy Technology Laboratory (NETL), is working to evaluate and demonstrate monitoring technologies including field-testing the applicability of single-well, cross-well, and surface-to-borehole seismic; cross-well EMT; and ERT. In addition, the GEO-SEQ project will conduct sensitivity modeling and optimization of geophysical monitoring technologies and assess the applicability of natural and introduced chemical tracers for optimizing value-added sequestration technologies (Cole and Phelps, 2003; GEO-SEQ, 2004).

The GEO-SEQ project is working with industry to provide test results and demonstrate the applicability of monitoring technologies in various formations. Test sites include the following:

- Lost Hills, California
- Vacuum Field, New Mexico
- Weyburn Field, Saskatchewan
- Fenn-Big Valley, Alberta

The combined use of cross-well seismic and electromagnetic imaging for monitoring CO₂ sequestration at an EOR site is being demonstrated at the Lost Hills test site in California (Hoversten et al., 2002; Kirkendall and Roberts, 2001). The impetus for the study is to develop the ability to image subsurface injected CO₂

during EOR processes while simultaneously discriminating between preexisting petroleum and water deposits. The study will primarily focus on how joint field and laboratory results can provide information on subsurface CO₂ detection, CO₂ migration tracking, and displacement of petroleum and water over time (Kirkendall and Roberts, 2001).

Rocky Mountain Oil Field Testing Center (RMOTC), Teapot Dome

The Teapot Dome Field Experimental Facility in Casper, Wyoming—also known as the Teapot Dome National Geologic Carbon Storage Test Center—will serve as a platform for field experiments directed at investigating geological CO₂ sequestration. The field contains over 1600 wells, with a range of logging tools and cores, over 100 years of production data including steam and waterflooding data, and a recent 3-D seismic survey. The field includes both siliciclastic and carbonate reservoirs as well as a wide range of depositional systems including eolian, fluvial, tidal, deltaic, and shoreface units, some with significant fracture permeability, providing a great geological, geophysical, and geochemical range for demonstration activities (Friedmann, 2003). MM&V technologies will include multicomponent 4-D seismic surveys, VSP, cross-well seismic tomography, and nontraditional geophysical technologies such as ERT and downhole triaxial microseismic arrays. Geochemical techniques will include soil chemistry surveys, wellhead gas chromatography, noble gas isotopic tracer studies, other tracers (i.e., PFCs), and repeated brine, matrix, and caprock sampling. Hyperspectral imaging was scheduled to begin in fall 2004 within the context of a methane pipeline leakage study led by RMOTC and DOE (Friedmann et al., 2004).

Additional Research Considerations

In order to effectively demonstrate the applicability of MM&V technologies to a

broad scale of potential CO₂ sequestration activities, it is necessary that near-term demonstrations and field experiments cover a wide range of geological conditions. While both the Sleipner and Weyburn projects provide excellent examples for the potential for CO₂ storage, they are not necessarily representative of future storage options. For instance, the large thickness (>300 ft), high porosity (>30%), high permeability (>3000 mD), and high sand percentage (>90%) of the Utsira Formation are unusual and not representative of most saline formations in the United States, Europe, or sedimentary basins worldwide (Friedmann, 2003). Weyburn, in contrast, is typical of many target reservoirs in terms of injection depths, permeability, porosity, and imaging potential; however, it has an uncommonly strong, dense, and impermeable anhydrite caprock (Friedmann, 2003; Nickel, 2004). Appendix A presents some of the many geological variables and their associated uncertainties that must be considered in an effort to understand the true variability of large-scale deployment of CO₂ storage projects. Storage demonstrations or field experiments that utilize several formations with wide-ranging geological characteristics will maximize the scientific and technical development.

The determination of migration pathways and rates of reaction between CO₂ and rock formation and aqueous phases is necessary to estimate the magnitude of mineral and solubility trapping as well as effects on porosity, permeability, and reservoir integrity (Bruant et al., 2002). In addition, numerical simulators of multicomponent transfer coupled with geomechanics, geochemistry, and heat transfer are needed to predict the fate and transport of CO₂ in the subsurface. The GEO-SEQ project is currently focused on enhancing, developing, and verifying subsurface transport models for this purpose (GEO-SEQ, 2004). While current field-monitoring demonstrations have used

3-D and 4-D reflection seismology to monitor plume migration, relatively little effort has focused on using seismic data and multicomponent arrays to quantify the nature, concentration, and chemical phase of the CO₂ in the subsurface.

Regulatory Requirements and Considerations for MM&V in Geological Sequestration

Current regulatory requirements for MM&V of enhanced-recovery operations, natural gas storage, and waste disposal may be adapted for use in CO₂ capture and storage projects and require modification to adequately address the needs for verifying the efficiency of long-term geological storage of CO₂. Current logging and testing requirements for waste disposal injection wells include 1) continuous monitoring of injection flow rates and pressures; 2) annual monitoring using radioactive tracer logging, annulus pressure testing, and reservoir testing; 3) temperature logging, casing inspection logging, and cement bond logging conducted every 5 years; and 4) mechanical integrity testing for well abandonment. Current regulations for waste injection do not require separate monitoring wells. Methods developed by the oil and gas industry, including injection well pressure monitoring and 3-D seismic surveys, may be used to verify storage efficiency and provide early warning in the event of failure. However, more site-specific studies are needed to adequately demonstrate their sensitivity and to develop effective MM&V strategies.

Site-specific investigations will also be required to effectively define risk mitigation and remediation strategies in the event of reservoir failure. Existing regulations for hazardous waste disposal, acid gas injection, and natural gas storage provide an adequate framework for protecting local environmental and human health in CO₂ storage operations; however, these regulations may not adequately address

concerns of long-term environmental impact (i.e., global climate change). To mitigate long-term impacts, MM&V requirements must address the potential problem of wide-scale diffuse leakage from geological formations.

MM&V Strategies for the PCOR Partnership Region

The following sections present a framework for MM&V in three geological CO₂ storage options—EOR, deep saline formation disposal, and enhanced coalbed methane (ECBM) recovery or disposal in unminable coal seams—identified in the PCOR Partnership region. Additional site-specific information will be required for further development and implementation of a successful MM&V strategy.

General Requirements for Geological Sequestration

Geological monitoring activities should focus on 1) the physical and chemical integrity of the sink, 2) leakage to the atmosphere including ecosystem impacts, 3) subsurface extent of the CO₂ plume, and 4) impact on the local and regional geological and hydrogeological framework. To effectively evaluate the long-term storage of CO₂, geophysical and geochemical investigations should be conducted prior to CO₂ injection, during CO₂ flooding, and for a determined period of time following completion. MM&V for geological sequestration may include, but not be limited to, the following activities:

- *Establish baseline “surface” geochemical characteristics.* The goal of this activity is to establish natural background concentrations of soil gases, which will be compared to later soil gas surveys in order to detect changes in concentrations that may be indicative of leakage from the reservoir. In addition, trace hydrocarbons or hydrocarbon indicators could be mapped for trends.
- *Identify potential pathways for leakage.* Remote imaging, in addition to soil gas sampling and hydrocarbon indicator mapping, may help identify potential leakage pathways by discerning topographical or vegetative surface features correlating with subsurface faults or fractures.
- *Conduct groundwater monitoring.* In order to ensure the protection of potable water sources and effective injection and storage of CO₂, groundwater sampling must be conducted at regular intervals throughout the project lifetime.
- *Establish stress regime and geomechanical properties of the injection reservoir and caprock.* The goal of this activity is to establish the geomechanical properties of the reservoir and caprock and the stress regime in the area to ensure the mechanical integrity of the system and avoidance of potential rock fracturing.
- *Observe dynamic response of reservoir to CO₂ injection.* Field-based activities need to be conducted to monitor pressure, temperature, pH, resistivity, changes in bulk fluid density and volume, and seismicity within the reservoir. Microseismic monitors could be used to monitor potential movement of caprock due to injection.
- *Conduct seismic monitoring.* Seismic monitoring is the preferred method for evaluating the movement and subsequent residence of an injected gas plume within a geological sink. Modeling based on seismic results can be used to verify the integrity of the intended sequestration sink,

while postinjection seismic surveying would provide an invaluable means of actually assessing the storage effectiveness of the target formations. Surface seismic techniques may provide adequate measurements for assessing storage effectiveness; however, higher-resolution interwell geophysics could be considered should funds be available.

- *Assess wellbore integrity.* Laboratory activities may be conducted to determine the stability and reactivity of cement and/or casing to CO₂ and modified formation fluids. Additionally, an assessment may be conducted on the integrity of the injection well and other wells in the vicinity that may be reached by the injected CO₂.
- *Monitor potential conduits of leakage (i.e., injection wellbore, monitoring wells, and abandoned wells).* Monitoring of all infrastructure, including injection, monitoring, and abandoned wells, should be conducted during injection and for an established period of time after injection has ceased. In addition, low-lying areas and below-grade structures (i.e., abandoned mine shafts and pits) should be monitored for CO₂ accumulation.
- *Monitor produced waters and gases.* Continuous monitoring of produced waters and gases is necessary to determine when CO₂ breakthrough has occurred. It may also be used to assess compositional changes of formation waters resultant of CO₂.

Additional Considerations for EOR and Storage in Depleted Oil Reservoirs

Verification of geological CO₂ sequestration in EOR or straight reservoir storage operations will require careful monitoring

of horizontal and vertical migration as well as chemical transformation of CO₂ both within the storage reservoir and out of the confining formation. MM&V considerations for EOR or straight storage activities include:

- *Identifying abandoned wells and other potential leakage conduits.* Because of the large number of boreholes drilled since the advent of oil production in this region, in addition to insufficient record keeping, locating plugged and abandoned wells may prove challenging. There is additional concern that over time the integrity of cement plugs may be compromised, resulting in insufficient closure or that many abandoned wells may have been left without proper closure mechanisms altogether. The identification of faults and fractures may be obtained through well logs, geophysical surveying data, and topographical evaluation, which may show the expression of faults in surface features.
- *Determining the area of influence of injection.* It is necessary to identify the potential influence of injection.
- *Utilizing existing infrastructure for monitoring (i.e., former production or monitoring wells).* It is assumed that existing infrastructure will be used for MM&V operations. Construction of new observation wells would likely exceed budgetary constraints for MM&V, and it is thought that the leakage risks associated with any wellbore could exceed the value of data obtained through monitoring.
- *Monitoring and testing safety mechanisms.* Shut-in procedures for CO₂-enriched production waters as

well as other safety mechanisms must be routinely monitored and tested to ensure proper operation.

- *Issuing carbon credits.* Development of a system that will facilitate the issuing/trading of carbon credits by quantifying the total CO₂ stored during the tertiary recovery operation will be critical in EOR operations.

Additional Considerations for Storage in Deep Saline Formation

Constructing monitoring wells to depth of storage reservoir. The infrastructure for monitoring disposal of CO₂ in deep brine formations may be limited to, at most, wellbores constructed into overlying formations for production operations. Monitoring wells may be constructed to the depth of the storage reservoir. However, construction may be cost-prohibitive and may not provide clear data, given the uncertainty inherent with well placement, and wellbores could create a pathway for leakage that may not otherwise exist.

Additional Considerations for Storage in Unminable Coal Seams or for ECBM Recovery

Constructing monitoring wells. Monitoring wells may or may not be in place for projects utilizing unminable coal seams. For active ECBM recovery sites, additional monitoring wells may not be required. For new sites where ECBM recovery may be desired, construction of new wells will be necessary. As with other storage options, new wellbores increase the potential for leakage of CO₂ to overlying formations, groundwater, surface water, and the atmosphere.

MM&V Implementation Plan for Geological Sequestration Options in the Region

Three geological sequestration technology options were selected for field validation testing in the PCOR Partnership region in this Phase I study: 1) an EOR-focused

project injecting CO₂ into a carbonate formation at much greater depths than previous investigations, 2) a project that will test the suitability of lignites for CO₂ sequestration and possible ECBM recovery, and 3) a project that utilizes acid gas injection for EOR. For each field test project, the preinjection baseline site characterization efforts will include geological modeling, calculations to estimate the expected storage capacity, and laboratory tests to predict possible interaction of the injected gases with the reservoir rock and fluids. The reliability of the preinjection modeling predictions and calculations will be assessed by material balance comparison as well as by assessment of the percent effective utilization of the available storage capacity and evaluation of postinjection reservoir conditions. MM&V technologies will be applied at the demonstration sites as deemed appropriate based on the unique nature and needs of each site and according to the constraints of the budget. With respect to risk assessment, MM&V techniques will verify net avoided CO₂ emissions, assess the effective utilization of the available reservoir capacity, optimize EOR and ECBM production operations, and ensure public safety.

Injection of CO₂ into Carbonate System at Beaver Lodge Oil Field, North Dakota

The proposed field validation activities will be conducted in the Beaver Lodge oil field in northwestern North Dakota to evaluate the potential for geological sequestration of CO₂ in a deep carbonate reservoir for the dual purpose of CO₂ sequestration and EOR. Phase I assessments have indicated that the Beaver Lodge Field may have up to 200 million tons of CO₂ storage capacity in three separate pools. The target injection zone for the project will be the Duperow Formation, which is located at a depth between 10,000 and 10,500 ft. In comparison, the Weyburn CO₂ project is operated at depths of 4750 ft. The Duperow is primarily dolomite with an

average porosity of 13.7%, permeability of 3.6 md, and other reservoir properties that make it a suitable target for CO₂ sequestration. Amerada Hess Corporation owns and operates the field and will make it available for the proposed activities.

Amerada Hess has rigorously evaluated the properties of the site selected for the EOR demonstration project, including robust reservoir modeling activities. Additional reservoir modeling based on data collected over the course of the injection operations will be conducted. Construction requirements for the proposed operation will include the installation of CO₂ injection wells and the infrastructure and facilities necessary to transport the CO₂ from the Dakota Gasification Company (DGC) pipeline to the Beaver Lodge Field. Monitoring and verification equipment will be installed and operations conducted to monitor pressure, temperature, pH, resistivity, and changes in bulk fluid density and volume within the reservoir. Microseismic monitors may be used to monitor potential movement of caprock due to CO₂ injection. Monitoring of CO₂ phases with natural stable isotopes and/or other tracers may be conducted. Risk mitigation will be accomplished by monitoring the surface soil gas and ambient air for increases in CO₂ and/or other tracers.

Injection of CO₂/H₂S (acid gas) into Carbonate System at Zama, Alberta

The proposed field validation test to be conducted in the Zama Field of Alberta will evaluate the potential for geological sequestration of CO₂ as part of an acid gas stream that includes high concentrations of H₂S. The acid gas will be injected for the purposes of CO₂ sequestration, H₂S disposal, and EOR. The results of Zama activities will provide insight regarding the impact that high concentrations of H₂S (35% or greater) can have on sink integrity (i.e., seal degradation); monitoring, mitigation, and verification; and EOR

success within a carbonate reservoir. Activities will include reservoir simulation modeling based on data collected over the course of the injection operations. Monitoring and verification equipment will be installed and operations conducted to monitor pressure, temperature, pH, resistivity, and changes in bulk fluid density and volume within the reservoir. Microseismic monitors may be used to monitor potential movement of caprock. Monitoring of CO₂ phases with natural stable isotopes and/or other tracers may be conducted. Risk mitigation will be accomplished by monitoring the ambient air for CO₂ and H₂S.

Injection of CO₂ into Lignite Coal Seam in North Dakota

The proposed demonstration project will examine the effectiveness of lignite coal seams to act as sinks for CO₂. Field validation of the potential for simultaneous CO₂ sequestration and ECBM production will be conducted in a lignite seam in western North Dakota. The target injection zone will be in the Harmon coal seam. At 16 m, it is the thickest known lignite in North Dakota. Preliminary estimates of the potential coalbed methane reserves and effective CO₂ storage capacity of the Harmon coal seam have been made. The total coalbed methane gas-in-place for the Harmon has been calculated to be as high as 4.4 tcf. The effective CO₂ storage capacity of the Harmon coal seam is about 5.6 tcf (328 million tons). Together, these calculations support the conclusion that the Harmon coal seam is desirable for the study.

The goal of the proposed project will be to determine whether long-term contact with CO₂ affects the physical stability and gas storage capacity properties of lignite coal and hydrodynamic properties of the seam. In addition, the practicality and economics of using CO₂ to enhance natural gas recovery from lignite coal seams will be evaluated. Construction requirements

include the drilling of injection, production, and observation wells into the coal seam. CO₂ will be brought to the site via truck. It is anticipated that a minimum of 400 tons will be injected. Monitoring and verification equipment will be installed and operations conducted to monitor pressure, temperature, pH, resistivity, and changes in bulk fluid density and volume within the reservoir. Risk mitigation will be accomplished by monitoring the surface soil gas and ambient air for changes in CO₂ levels and changes in the water chemistry of the overlying aquifer system.

MEASUREMENT, MONITORING, AND VERIFICATION OF TERRESTRIAL SEQUESTRATION

Unlike geological carbon sequestration, storage of CO₂ in terrestrial ecosystems, as conducted today, poses no direct risk to human health and safety and, therefore, requirements for monitoring, measurement, and verification are solely for the purpose of accounting in a greenhouse gas market. Two important considerations in monitoring and verifying terrestrial sequestration include leakage and baseline assessment. The term *leakage*, when discussed in terrestrial sequestration, may refer to loss of stored carbon as a result of natural or engineered land use change (i.e., forest fires or change in land management practices following a given period of time over which CO₂ was actively being sequestered) or to the offset of carbon losses through changes in activities outside of the project area (i.e., reforestation or afforestation in one area may stimulate deforestation in another) (Gregg et al., 2001). Baseline assessment is the approximate measurement of the carbon that would have been stored without the sequestration project. Baseline carbon stock changes may be difficult to assess and will likely require modeling or control plots.

Technologies and Strategies for Measuring, Monitoring, and Verifying Terrestrial CO₂ Sequestration

There are several approaches currently used to estimate carbon stored as a result of a particular land management practice. These approaches include the following:

- Direct measurement of soil carbon, biomass, or CO₂ flux
- Indirect remote sensing techniques
- Use of default values assigned to various land use practices

These approaches may be used independently or may be combined depending on the level of accuracy required for monitoring and verification efforts. The use of default values for activity-based practices provides the lowest level of accuracy, but provides a cost-effective method for assessing carbon storage over a large area. Verification under this approach would only require that monitoring be conducted to show that a particular land management practice is being used on the land in question.

Several techniques are currently available or in development for monitoring, measuring, and verifying terrestrial sequestration of CO₂ (Table 4). As with geological storage, a combination of monitoring and verification technologies and methodologies may be necessary to adequately assess the effectiveness of the carbon sequestration project. The level of precision required may vary with each sequestration project, depending on the purpose for which measurements are applied (i.e., compliance with laws regulating CO₂ emissions vs. assignment of carbon credits or offsets under a voluntary carbon emissions reduction program).

Soil Carbon Measurements

Current methodologies for measuring soil organic carbon (SOC) typically rely on laboratory techniques that are both time-consuming and analytically expensive.

Table 4. Monitoring, Measurement, and Verification Methods Applicable to Terrestrial CO₂ Sequestration

In Situ Soil Carbon Measurements	<ul style="list-style-type: none"> • Field-portable LIBS • Noninvasive advanced Raman detection system (ARS) • MIR/NIR • INS • Laboratory analysis of soil samples (wet or dry combustion)
Above Ground Biomass Measurements	<ul style="list-style-type: none"> • Satellite imagery or aerial photographs • Destructive ground sampling • Biomass equations based on allometry (study of the relative growth of a part of an organism in relation to the growth of the whole)
Remote Sensing	<ul style="list-style-type: none"> • Advanced very high resolution radiometer (AVHRR) • Landsat and SPOT satellite data • Airborne visible infrared imaging spectrometer (AVIRIS) – hyperspectral imaging • Very high-frequency (VHF) synthetic aperture radar (SAR) for airborne remote sensing of biomass and carbon • Scanning Lidar • Aerial photography
Carbon Flux	<ul style="list-style-type: none"> • Eddy covariance measurement of CO₂ fluxes over a vegetated surface
Modeling	<ul style="list-style-type: none"> • Models linked to databases and driven by remote sensing input (e.g., Century and CQESTR)

Emerging technologies focus on noninvasive and/or field-portable techniques that can provide in situ measurements. Examples of such technological advancements include laser-induced breakdown spectroscopy (LIBS), advanced Raman fiber optic-based analysis (Cremers et al., 2001; Wullschleger et al., 2001), mid- or near-infrared spectroscopy (MIR/NIR) (McCarty et al., 2002), and inelastic neutron scattering (INS) (Wielopolski et al., 2000).

In order to assess changes in SOC, sampling schemes must consider vertical and horizontal heterogeneity, current SOC in relation to carbon inputs and plant productivity, and movement of SOC within a field. A well-designed sampling matrix

will consider spatial variations in a field in determining temporal changes in carbon due to alternative sequestration practices. Returning to the same area each time for sampling will also reduce variability. To improve confidence in sampling results, sampling should begin several years before sequestration practices are put into place or additional samples should be collected simultaneously on similar plots or nearby land maintained under traditional management during the study period. Current methods for measuring changes in SOC are effective at relatively low precision (20% to 50% error) and at widely spaced time intervals (minimum of 3 to 5 years) (Post et al., 2001).

Simulation Models and Scaling

Indirect methods including soil carbon modeling or simple extrapolation of soil carbon changes measured directly at the plot and field scale are necessary to estimate carbon storage over large areas of land. Scaling SOC changes from sites to regions generally requires subdividing the landscape into relatively homogeneous plots, applying field measurements or model predictions to each subdivision, and computing the area-weighted totals. Successful scaling can be a formidable task and is dependent on the availability of comprehensive soil, land cover, climate, and management databases.

With continuous improvement, soil carbon models are becoming better equipped to reliably predict the effects of alternative practices on SOC. Examples of soil carbon models available include the Century SOC model, developed by the Colorado State University Natural Resources Ecology Laboratory and the USDA Agricultural Research Service (ARS) and the CQESTR model, developed by the USDA ARS. The Century SOC model simulates dynamics of carbon, nitrogen, sulfur, and phosphorus in the top 20 cm of the soil as well as soil water balance, crop growth, and dry matter production and yield (www.nrel.colostate.edu/projects/century5). The CQESTR model predicts how agricultural management systems affect organic carbon storage in soils and is sensitive to local soils, climate, tillage, crop rotation, cover crops, and organic amendments (www.ars.usda.gov/is/AR/archive/feb01/bank0201.pdf).

Biomass Carbon Measurements

While carbon measurement in above-ground biomass is particularly important in estimating CO₂ sequestration in forestry or agroforestry, it is also necessary for calculating annual carbon budgets in other terrestrial sequestration practices. Remote imaging or aerial photographs and ground sampling can be used to estimate biomass

yield. For woody species, above-ground biomass carbon can be estimated by using local or generic allometric biomass regression equations, adjusting calibration equations through field sampling including destructive biomass sampling. Typical methods for sampling below-ground biomass include use of spatially distributed soil cores or pits for fine and medium roots and partial to complete excavation and/or allometry for coarse roots. Root biomass is often estimated from root:shoot ratios (Brown, 2001).

Eddy Covariance Measurements

The net uptake or release of carbon from soil and vegetation can be calculated by quantitatively measuring CO₂ in the vertical component of air moving over a vegetated surface (eddies). The precision and accuracy of eddy covariance measurements have greatly improved over the last two decades as a result of advancement in instrumentation, data acquisition systems, and increased experience in estimating fluxes when operating the systems under less than ideal conditions (Post et al., 2001). The net flux in carbon measured has two components: 1) changes in carbon stock of the vegetation and 2) changes in carbon stock of the soil. Because changes in vegetation carbon content are typically easier to measure directly than changes in soil carbon (with the exception of vegetation roots), changes in soil carbon are generally calculated as the difference between the measured net ecosystem exchange and the change in carbon stored in the vegetation. Understanding the changes in carbon fluxes over short time scales may be useful in assessing results from direct sampling of SOC and carbon stored in vegetation.

Remote Sensing

Remote sensing techniques are available for estimating biomass yield and leaf area index as well as mapping soil carbon distribution. Current sensors or platforms with potential application to sequestration activities include AVHRR, AVIRIS, CARABAS-II VHF SAR, Landsat, and SPOT satellite data. While remote imaging may supplement monitoring and verification activities, it is unable to directly estimate SOC without ground-based data.

To improve the applicability of remote sensing in assessing carbon stock in forestry biomass, sensors that have the ability to measure the height of the canopy or vertical structure will be needed in addition to more traditional sensors available on Landsat and SPOT satellites. Two promising technological advancements in this area include 1) scanning Lidar that explicitly measures canopy height and 2) the coupling of dual-camera digital videos with a pulse laser profiler, data recorders, and differential GPS (global positioning system) mounted on a single-engine plane, producing data that can determine tree crown area, tree height, crown density, and number of stems per unit area (Brown, 2001).

Voluntary Reporting of GHG Emissions for 1605(b) Program

Guidelines for the DOE Section 1605(b) Voluntary Greenhouse Gas Reporting Registry were released on March 22, 2005, for public comment. The revised voluntary reporting program provides agriculture and forest landowners with the ability to quantify and maintain records of actions that have GHG reduction benefits including use of no-till agriculture, installation of a waste digester, improved nutrient management, and management of forestland (Enviro-News, 2005). In addition, the program provides opportunities for agriculture and forestry operations to partner with industry in

developing actions to reduce greenhouse gases.

The new agricultural and forestry guidelines provide farmers and ranchers with the **Voluntary Reporting of GHG CarbOn Management Evaluation Tool** (COMET-VR). COMET-VR is a decision support tool that uses the Century SOC model simulation and data from the Carbon Sequestration Rural Appraisal (CSRA) to calculate in real time the annual carbon flux for various land management practices (www.cometvr.colostate.edu). User input includes a history of agricultural management practices on one or more parcels of land. Estimates of soil carbon sequestration or emissions are presented as 10-year averages, which can be used to construct a soil carbon inventory for the 1605(b) program.

Verification for Carbon Credit Trading

Standardized rules or protocols for quantifying terrestrial sequestration using sound scientific measurement practices are necessary in developing a successful market for trading carbon credits. Today, the Chicago Climate Change (CCX[®]) operates a pilot market for trading carbon credits throughout North America. CCX[®] is a voluntary, rules-based, self-regulatory exchange that issues carbon credits for carbon sequestration resulting from continuous no-till, strip-till, or ridge-till cropping; grass plantings; and tree plantings, as well as emission reductions resulting from agricultural methane collection or combustion systems. Issuance of carbon credits is based on storage quantification protocols developed by CCX[®].

Measurement, Monitoring, and Verification Strategies for the PCOR Partnership Region

There are numerous opportunities for enhancing terrestrial sequestration in the PCOR Partnership region through adopting land management practices that promote

carbon buildup in biomass and soils. These practices include conservation tillage, reducing soil erosion, and minimizing soil disturbance; using buffer strips along waterways; enrolling land in conservation programs; restoring and better managing wetlands; restoring degraded lands; converting marginal croplands to wetlands or grasslands; eliminating summer fallow (EIA, 2005; Lal et al., 1999) using perennial grasses and winter cover crops; and fostering an increase in forests (Cihacek and Ulmer, 2002).

Alternative Agricultural Practices and Wetland Restoration

Agricultural lands (both farm- and rangeland) and wetlands total more than 402 million acres and 30.9 million acres (Statistics Canada, 2001; South Dakota Partners for Fish and Wildlife, 2005) respectively, in the PCOR Partnership region and present considerable opportunity for carbon sequestration through employment of alternative land management practices (Saskatchewan, 2005; National Agricultural Statistics Service, 2005). Because of wide differences in soil type, topography, climate, and land management, estimating carbon stored as a result of land use change throughout the PCOR Partnership region poses a formidable challenge. Carbon sequestered or sequestration potential may be estimated based on 1) actual field- or plot-level sampling data and/or 2) use of soil carbon simulation models with or without ground truthing. Field- or plot-level estimates can be extrapolated to cover analogous land in the region. General requirements for estimating sequestration potential through the use of alternative agricultural practices include the following:

- Define climatic zones.
- Determine distribution of primary soil types.

- Determine distribution of land uses on each soil type.
- Define preclearing SOC levels for each soil type according to climatic zone.
- Define land use and management activity/history for each soil type according to climatic zone.
- Determine SOC pool structure.

Forestry and Agroforestry

Forested areas within the PCOR Partnership region total more than 302 million acres (Alberta Geological Survey, 2005; State Foresters, 2002; University of British Columbia Forestry, 2005; Institute of Cognitive Sciences, 2005). While land use change and forest management activities have historically resulted in net CO₂ emission, opportunities exist to enhance carbon sequestration through 1) conservation (i.e., reduction in deforestation or adopting improved forest harvesting practices), 2) increasing forest land area coverage or carbon density of forests, and 3) increasing storage in durable products.

Measuring carbon stored in forests typically includes assessment of live biomass (above-ground and below-ground), detritus, and soils. While specific MM&V strategies will vary depending on the project type (i.e., afforestation, reforestation, agroforestry, biomass enrichment, etc.) and requirements for accuracy, there are several common methods employed in monitoring changes in carbon stock (as described in *Guidelines for the Monitoring, Evaluation, Reporting, Verification, and Certification of Forestry Projects for Climate Change Mitigation* [Vine et al., 1999]):

- *Establish the monitoring domain.*
Monitoring and measurement

techniques are most effective when they are based on permanent sample plots laid out in a statistically sound design. Provided the plots are representative of the larger area for which the estimates are intended, permanent plots can allow for reliable and efficient assessment of changes in carbon stock over time.

- *Model impacts of forestry practices on carbon flux.* Models can be used to estimate annual carbon flux and predict future carbon changes; however, they cannot measure actual changes in carbon stock. Modeled estimates must be checked with other evaluation and measurement techniques (i.e., remote sensing with ground truthing or field measurement).
- *Utilize remote sensing techniques.* Remote sensing, when used in conjunction with ground-based measurements, can be used to monitor land area changes, map vegetation types, delineate strata for sampling, and assess leakage and base case assumptions. Remote sensing for forestry projects may include high-level and/or low-level techniques (i.e., satellite imagery and/or aerial photography).
- *Conduct field/site measurements.* Field site measurements may include assessment of above- and below-ground biomass and soil carbon through surveying and/or destructive sampling techniques.

Monitoring, Measurement, and Verification Implementation Plan for Terrestrial Sequestration Options in the Region

Several opportunities exist for terrestrial sequestration in the PCOR Partnership region. Two studies currently under way include the restoration of Prairie Pothole

Region (PPR) wetlands and an investigation of alternative agricultural land management practices along the western North Dakota–South Dakota border. Monitoring, measurement, and verification strategies are presented in the following sections.

Restoration of Prairie Pothole Region Wetlands

The PPR of the northern Great Plains contains a vast wetlands complex, approximately 276,000 mi², covering portions of Iowa, Minnesota, North Dakota, South Dakota, Montana, Saskatchewan, Alberta, and Manitoba. USGS collected carbon sequestration data from approximately 480 wetlands in the U.S. PPR in 1997 and 2004 (USGS, 1997, 2004), and Ducks Unlimited Canada (DUC) collected similar data from approximately 100 wetlands in Canada during 2002 and 2003. Based on carbon data collected during 1997 and the 1997 National Resources Inventory (USDA, 1994) data on wetlands in cropland, it is estimated that the restoration of cropland wetlands would result in the sequestration of over 7.2 million tons of SOC per year for up to 150 years.

USGS and DUC will continue to develop and refine the database for estimating the potential of prairie wetlands to sequester carbon through intensive field investigations of farmed (baselines), restored, and native wetlands (maximum potential) in the PPR. A monitoring plan would include the following:

- *Measure CO₂, N₂O, and CH₄ flux.* CO₂, N₂O, and CH₄ flux and associated characteristics critical to understanding the sequestration process would be measured biweekly during the ice-free months.
- *Monitor climatic conditions.* To account for climatic factors that influence gas emissions, each wetland would be equipped with a

weather station, temperature data loggers (near each chamber), and rain gauges to provide hourly or biweekly measurements of climatic data.

- *Conduct soil sampling.* To account for variation in soil properties that influence emissions, soil would be collected along transects each season, or benchmark sites, for determination of physical and chemical attributes using standard methods.

Data collected would be analyzed to compare GHG emissions among wetland land use categories. Information on SOC sequestration and gas emissions could be used to estimate global warming reduction potential of restored wetlands relative to baseline conditions (i.e., farmed wetlands) and, ultimately, to quantify marketable carbon offsets.

Use of Alternative Land Management Practices in Agriculture

The effects of land management and land use on soil carbon are being evaluated at the Hettinger Research and Extension Center (HREC) in Hettinger, North Dakota. The study has included economic modeling and investigation of sequestration potential for three possible land management/land use alternatives: 1) maintaining current farm practices, 2) switching tillage practices, or 3) converting cropland to permanent grass. The geographic scope of the study was limited to a four-county region in the southwest corner of North Dakota to coincide with the same soil type, growing conditions, and production practices associated with ongoing research at the HREC. Since site-specific factors, such as soil type, climatic conditions, historical land use patterns, crop rotations, and existing management systems, have an influence on carbon sequestration rates, the goal at the onset of the study was to use HREC research data

to determine carbon sequestration rates for the study region. Unfortunately, the breadth of data currently available from field trials was deemed insufficient for economic modeling. As a result, despite limiting the geographic scope of the study to directly coincide with HREC research, secondary sources had to be used to develop carbon sequestration rates. Secondary data, while commonly used for soil carbon modeling, are usually aggregated to be representative of larger geographic regions and are likely to be less precise than data obtained from field experiments when applied to a specific set of local conditions.

REGULATING CARBON CAPTURE AND GEOLOGICAL STORAGE

“Regulations often evolve incrementally from existing regulatory structures and experience, an effect that often dictates much of the initial regulatory framework. Absent adequate understanding and debate about the appropriate regulatory environment, there is a risk that regulators will act abruptly, crafting a regulatory structure to fit the demands of a few early geologic sequestration projects, without adequate understanding of the long-term implications of their rule making” (Wilson et al., 2003).

The development of a regulatory framework, based on science and designed with the flexibility required to encourage a reduction in CO₂ emissions, while providing protection for environmental and human health and verification of effective storage, will undoubtedly prove challenging (Forbes, 2002). At this time, the demonstration and implementation of CO₂ capture and storage are outpacing development of an appropriate regulatory framework for managing sequestration projects. Discussions in the United States have primarily ensued over the current underground injection control (UIC) framework and well classification. Based

on extensive experience with CO₂ injection for enhanced recovery operations under Class II injection well designation, many argue that the more stringent requirements associated with a suggested Class I permit are unnecessary and cost-prohibitive. In opposition, advocates for Class I designation argue that the stringent requirements for monitoring and reporting are necessary to provide assurance that CO₂ is not migrating from the storage reservoir and that the price tag associated with this assurance is justifiable.

In lieu of regulatory requirements for reduced emissions, economic incentives driving CO₂ storage at this time are associated with enhanced recovery operations. Without an additional economic driver, large-scale implementation of CO₂ storage will only be possible if regulations are not cost-prohibitive to industry operations. Verification of storage efficiency, with the exception of managing local risks, will only become imperative under a policy that imposes constraints on CO₂ emissions. Under cap and trade, GHG market, or regulatory regimes, MM&V that is well calibrated, reproducible, and able to be widely deployed will be necessary. Carbon credit trading, while critical to the success of CO₂ sequestration, is not comprehensively addressed in this report.

The Interstate Oil and Gas Compact Commission (IOGCC) Geological CO₂ Sequestration task force, working with member states and the seven RCSPs, was given the task of developing regulatory guidelines for CO₂ sequestration. The primary objectives of the task force were to 1) examine the technical, policy, and regulatory issues related to safe and effective storage of CO₂ in the subsurface (oil and natural gas fields, coalbeds, and saline aquifers), whether for enhanced hydrocarbon recovery or permanent storage, and 2) produce a final report

containing an assessment of the current regulatory framework likely applicable to geological CO₂ sequestration and recommended regulatory guidelines and guidance documents, laying the groundwork for a state-regulated, but nationally consistent, regulatory framework (IOGCC, 2003). The PCOR Partnership was involved in the drafting and final preparation of this report, which was made publicly available April 2005 (www.iogcc.oklaosf.state.ok.us). Supplementing the work of the IOGCC, Keith and Wilson (2002) have developed comprehensive recommendations for the management of geological storage of CO₂ in Canada. This information will be of particular value for activities conducted within the PCOR Partnership's three Canadian provinces.

The following sections briefly summarize current regulatory regimes in the United States and Canada applicable to CO₂ capture and geological storage, gaps in current regulatory frameworks, uncertainties in geological sequestration, and considerations for managing sequestration.

U.S. Regulatory Framework

Capture and Separation

CO₂ capture is the separation of CO₂ from emission sources or the atmosphere and the recovery of a concentrated stream of CO₂ that is amenable to sequestration or conversion. Near- and midterm efforts of DOE are focused on capture of CO₂ from point sources, which can be broken into three broad categories: 1) flue gases from the combustion of fuels in air, 2) synthesis gases from oxygen-fired gasification, and 3) vents of highly pure CO₂ from various industrial processes (U.S. DOE, 2004). The CO₂ separation and capture methods identified below are conventional separation and capture options that are relevant for anthropogenic CO₂ emissions. These categories are not exhaustive

because obscure or undiscovered techniques could ultimately become preferred options. Performance characteristics, including CO₂ product purity and operating conditions, will differ because of operational or technical considerations for each of the methods identified.

The most likely options currently identifiable for CO₂ separation and capture include:

- Chemical and physical absorption.
- Physical and chemical adsorption.
- Low-temperature distillation.
- Gas separation membranes.
- Mineralization and biomineralization.

These were identified and included as probable options because of process simplicity, environmental impact, and economics. Currently, several CO₂ separation and capture facilities use one or more of these methods to produce CO₂ for commercial markets (U.S. DOE, 1999).

Vast numbers of state and federal regulations in the United States deal with emissions from industrial and energy generation facilities. To date, none of these regulations has classified CO₂ as a pollutant, and no regulations currently govern CO₂ emissions into the atmosphere. The United States has not yet promulgated any regulations addressing CO₂ emissions. However, its Global Climate Change Initiative has set a goal to reduce greenhouse gas intensity by 18% by 2012 through the support of voluntary efforts by industry.

CO₂ is not regulated, studied, or suspected as a toxic substance by the following federal agencies or regulations:

- Clean Air Act, 1970, 1990.

- Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), 1972.
- Resource Conservation and Recovery Act (RCRA), 1976.
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund), 1980.
- Superfund Amendments and Reauthorization Act (SARA), 1986.
- National Toxicology Program.
- Agency for Toxic Substances and Disease Registry.
- National Institute of Occupational Safety and Health (NIOSH) within the Center for Disease Control and Prevention.
- National Institute of Environmental Health Science in the National Institutes of Health.
- National Center for Toxicological Research (NCTR) in the Food and Drug Administration (FDA).

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's) hazardous materials guide treat CO₂ as a hazardous substance to the extent that any concentrated, pressurized, or cryogenic gas poses a danger (Benson et al., 2002). See Appendix B for a listing of the Code of Federal Regulations (CFR) relating to carbon dioxide.

Surface risks of CO₂ exposure are typically handled by state environmental health and safety regulatory agencies. For human health, the Occupational Safety and Health

Administration (OSHA) has specified the maximum average exposure of CO₂ over an 8-hour workday at 0.5% (5000 ppm). Most industrial and safety regulations for CO₂ focus on engineering controls and specifications for transportation, storage containers, and pipelines.

Transportation

The Department of Transportation Office of Pipeline Safety (OPS) regulates the pipeline transport of CO₂ under CFR Title 49, Part 195. Permitting for pipeline construction falls under numerous jurisdictions and varies by state. Table 5 summarizes the entities responsible for permitting the construction of pipelines in the PCOR Partnership region. Pipeline access for CO₂ transport is currently unregulated, as CO₂ pipelines are privately owned. When CO₂ is transported by rail, road, or ship, other rules, regulations, and agencies would have authority, and in some cases, there would be overlapping jurisdiction. This report focuses solely on the transportation of CO₂ via pipeline, as it is presumed to be the preferred method of transportation for large-scale sequestration projects.

Federal pipeline safety regulations:

- 1) ensure safety in design, construction, inspection, testing, operation, and maintenance of natural gas and hazardous liquid pipeline facilities and in the siting, construction, operation, and maintenance of liquefied natural gas (LNG) facilities;
- 2) set out parameters for administering the pipeline safety program;
- 3) require pipeline operators to implement and maintain antidrug and alcohol misuse prevention programs for employees who perform safety-sensitive functions; and
- 4) delineate requirements for onshore oil pipeline response plans. The regulations are written as minimum performance standards, setting the level of safety to be attained while allowing the pipeline operators discretion in achieving that level (U.S. DOT, 2004a).

A thorough, comprehensive compliance program, conducted by regional offices, is a key aspect of pipeline safety regulation. OPS regional offices are not only responsible for overseeing the compliance of interstate operators, but also responsible for monitoring the performance of state agencies participating in the federal/state pipeline safety program and performing inspections of interstate pipeline systems and those intrastate facilities not under state jurisdiction. In order to allocate its compliance resources in a manner which maximizes the impact on safety, OPS uses a computer-based tool known as the pipeline inspection priority program (PIPP). PIPP effectively directs inspections in accordance to level of risk by ranking pipeline units on system characteristics, filed reports, and accident data. OPS investigates major pipeline accidents to determine if regulatory violations occurred, if additions or revisions to the regulations are warranted, and to ascertain the cause of an accident. The purpose of an OPS investigation is to ensure the future integrity of the pipeline and develop a solid basis for any enforcement actions that may need to be taken.

This cooperative methodology is intended to increase the potential for developing widespread improvements in pipeline safety.

OPS is planning to use the interactive approval process it designed for the Oil Pollution Act of 1990 (OPA) as a model for risk management program review and approval process. Experience working with hazardous liquid operators on their oil spill response plans mandated by OPA has been a positive learning tool for OPS. It sees significant similarity between the success of the OPA experience and the potential to create a safer pipeline system through risk management practices with pipeline operators.

Table 5. Pipeline Permitting Authority for the United States Within the PCOR Partnership Region

Iowa – Iowa Utilities Board
Minnesota – Minnesota Department of Public Safety – Office of Pipeline Safety
Missouri – Missouri Public Service Commission
Montana – Montana Public Service Commission
Nebraska – Nebraska Public Service Commission
North Dakota – North Dakota Public Service Commission
South Dakota – South Dakota Public Utilities Commission
Wisconsin – Wisconsin Public Service Commission
Wyoming – Wyoming Public Service Commission

A joint government–industry team is currently working on the design of a new performance measurement system that will establish a baseline for the safety level operators have achieved under existing minimum federal safety standards. Examples include measures of operator performance, OPS performance, and overall safety performance.

Technical Pipeline Safety Standards Committee (TPSSC) and the Hazardous Liquid Safety Act of 1979 required the creation of the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC). The main purpose of these committees is to review proposed pipeline safety standards for reasonableness, technical feasibility, cost-effectiveness, and practicability. These committees also contribute to discussions related to pipeline safety policy issues and legislative initiatives.

Permitting for construction of CO₂ pipelines falls under various jurisdictions, and numerous permits may be required for any single project. In most cases, a pipeline route application is submitted to the permitting authority. Various aspects of the proposed pipeline construction must be addressed in the application including, but not limited to, right-of-way and easement considerations, cultural resources, visual resources, noise, socioeconomics, land use, geology and soils, water resources, air quality, and

terrestrial and aquatic ecological resources.

Crossing various types of water bodies and wetlands, federal lands, tribal lands, roadways, and railroads may and often does require permits from multiple agencies—local, state, and federal—that have jurisdiction over any of the mediums crossed. See Appendices C and D for state and provincial regulations and key legislation relating to the transport of CO₂.

CO₂ Injection and the Underground Injection Control (UIC) Program

Underground fluid injection is currently regulated by the U.S. Environmental Protection Agency (EPA) under the Safe Drinking Water Act (SDWA) UIC Program, established to protect current and future underground sources of drinking water (USDWs) from contamination. According to the SDWA, “*underground injection endangers drinking water sources if such injection may result in the presence in underground water that supplies, or can reasonably be expected to supply, any public water system of any contaminant, and if the presence of such contaminant may result in such system’s not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons*” (U.S. EPA, 2002).

Under the UIC Program, minimum federal standards were established for five distinct

classes of injection wells (Table 6) (40 CFR 144-148), which either could be adopted by state programs or implemented by EPA directly. In the 1980 reauthorization of the SDWA, two important provisions were made relating to the oil and gas industry. The first provision asserts that states need only regulate Class II oil- and gas-associated injection wells in an “effective manner,” while states are required to meet or exceed standards for all other classes of wells.

This provision, which removed uniformity in regulations throughout the United States, may have significant impact on the feasibility of geological CO₂ sequestration under the current regulatory framework. The second provision of the 1980 reauthorization allowed the exemption of natural gas injection for storage from federal regulation, based on the rationale that federal oversight might inhibit the needed expansion of gas storage. EPA has delegated to most states the regulation and monitoring of underground natural gas storage facilities. State programs are required to adequately address environmental health and safety issues, specifically, protection of USDWs from

endangerment by injection and storage of natural gas.

In the PCOR Partnership region, five states (North Dakota, Nebraska, Missouri, Wisconsin, and Wyoming) have been granted primacy for underground injection regulation; two states (Montana and South Dakota) share responsibility with EPA; and two states (Minnesota and Iowa) rely on EPA for UIC implementation. Table 7 summarizes state primacy programs for the PCOR Partnership region. Typically, in states with primary UIC enforcement, Class I wells are regulated by state departments of environmental or natural resources, while Class II wells are regulated by state conservation commissions or divisions of oil and gas.

The explicit goal of the UIC Program is to protect current and potential sources of public drinking water. Class I–III injection well regulations strictly prohibit migration of injectate into a USDW, defined as an aquifer containing a quantity of water sufficient to supply a public water system and a total dissolved solids content of less than 10,000 mg/L. However, there are no federal requirements for monitoring actual movement of fluids within the injection

Table 6. EPA UIC Program Injection Well Classification System (U.S. EPA, 2002)

Well Class	Injection Well Description	Approximate Inventory
I	Injection of hazardous waste, nonhazardous liquid, or municipal wastewater beneath the lowermost USDW.	500 (123 hazardous)
II	Disposal of fluids associated with the production of oil and natural gas, injection of fluids for EOR, and injection of liquid hydrocarbons for storage.	~147,000
III	Injection of fluids for the extraction of minerals including in situ mining of sulfur, uranium, or other metals and solution mining of salts or potash.	~17,000
IV	Injection of hazardous or radioactive waste into or above a USDW (banned unless injecting as part of authorized remediation).	40 sites
V	Injection wells not covered in Classes I–IV, typically involving shallow injection of nonhazardous liquid.	>500,000–685,000

Table 7. Enforcement of UIC Program for the PCOR Partnership Region

North Dakota – Department of Health (Classes I, IV, V); North Dakota Industrial Commission (Classes II and III)
South Dakota – EPA Region 8 (Classes I, III–V); South Dakota Department of Environment and Natural Resources (Class II)
Montana – EPA Region 8 (Classes I, III–V); Montana Board of Oil and Gas Conservation (Class II)
Minnesota – EPA Region 5 (Classes I–V)
Wyoming – Department of Environmental Quality (Classes I, III–V); Wyoming Oil and Gas Conservation Commission (Class II)
Nebraska – Department of Environmental Quality (Classes I, III–V); Nebraska Oil and Gas Conservation Commission (Class II)
Missouri – Department of Natural Resources (Classes I–V)
Wisconsin – Department of Natural Resources (Classes I–V)
Iowa – EPA Region 7 (Classes I–V)

zone, nor are there requirements for monitoring in overlying zones to detect leakage with the exception of specific Class I hazardous wells, where this type of monitoring can be—but rarely is—specifically mandated. Class IV wells, which were used to inject hazardous or radioactive wastes into or above USDWs, were banned in 1984 and, therefore, will not be included in further discussion. Regulations vary according to well classification and state requirements. In general, regulations for Class I, II, and III wells establish specific requirements for siting, construction, operation, testing, monitoring, reporting, and abandonment, including demonstration of financial capability to properly plug and abandon the wells upon completion of operations. Class V wells must comply with protective requirements set by EPA; however, no standard set of requirements, as prescribed for well Classes I–III, is specified for Class V injection wells.

To date, CO₂ injection has typically been regulated in conjunction with EOR

operations under Class II injection well requirements. Currently, no regulatory framework specifically addresses injection of CO₂ for purposes of long-term storage. Based on current and planned CO₂ sequestration demonstrations or operations, if regulated under the current UIC framework, it is anticipated that CO₂ injection will fall under Class I, II, or V injection well requirements. It is uncertain at this time if injection requirements for the explicit purpose of long-term CO₂ storage will be tailored according to formation type and in accordance with state primacy rules or if a uniform set of regulations for all formation types will be developed for nationwide implementation. In lieu of a national regulatory framework for CO₂ capture and geological storage, the IOGCC has developed a set of regulatory guidelines for state and federal use. It is not expected that the current regulatory framework developed for enhanced recovery operations will be modified unless a need arises for long-term verification of CO₂ storage.

The following sections compare the regulatory requirements set by EPA for Class I, II, and V wells (state regulations and requirements may exceed those set by EPA). Class III injection wells are not included in this summary as there is no precedence for their use for CO₂ injection. Regulatory requirements for Class I injection wells vary for hazardous and nonhazardous wastes. While CO₂ is not considered a hazardous waste by any regulatory authority, Class I hazardous waste injection requirements are included in this summary because they represent the most stringent regulatory requirements for UIC and have been suggested by some for the long-term storage of CO₂ in deep brine reservoirs.

Well Classification and Fluid Types (Classes I, II, and V)

Class I injection well requirements are designed to isolate hazardous, industrial, and municipal wastes through deep injection beneath the lowermost USDW. Examples of Class I well injectates include manufacturing and mining wastewater, RCRA hazardous waste, treated municipal effluent, and radioactive waste.

Class II injection wells are designated for the safe injection of fluid brought to the surface in connection with oil- and gas-related production for enhanced recovery of oil or natural gas or for liquid hydrocarbon storage. Examples of Class II injection well fluids include produced high-salinity brine, crude oil (for storage), polymers and viscosifiers for EOR (including CO₂), and drilling fluids and muds. Approximately 30 Mt of CO₂/yr, or 1.4 Bcf per day, is injected in the United States for EOR operations (Kovscek, 2002).

Class V injection wells are designated for the safe shallow injection of nonhazardous fluids, typically into or above USDWs. Class V injection wells may be used for wastewater disposal, including but not limited to storm water runoff, incidental

and process wastes from industry, car wash water, food-processing wastes, treated sanitary wastes, septic wastes, drainage from agricultural activities, and aquifer remediation. Beneficial uses of Class V wells include aquifer recharge, aquifer storage and recovery, subsidence control, saline intrusion barrier, and brine return from mineral recovery and energy production. Class V injection wells are also designated for demonstration of experimental technologies involving injection of nonhazardous waste. Current demonstrations at the Frio Brine Pilot Experiment in Texas utilize a Class V well for limited injection of CO₂ for the purpose of demonstrating MM&V technologies and gaining knowledge of how CO₂ behaves in the receiving formation (Hovorka et al., 2004).

Siting and Construction (Classes I, II, and V)

General construction and siting requirements set by EPA for Class I and Class II injection wells are summarized in Table 8. There are no specified requirements for the construction and siting of Class V injection wells, only a general protective requirement that injection cannot endanger a USDW.

All Class I wells must be sited in a geologically stable area free of transmissive faults or fractures through which injected fluids could travel to sources of drinking water. Injection well operators must demonstrate through geological and hydrologic studies that injection will not endanger USDWs and that the injection zone is of sufficient lateral extent and thickness and sufficiently porous and permeable to accept fluids without excess pressure buildup or displacement of reservoir fluids out of the storage reservoir. Operators must also demonstrate that injected fluids are geochemically compatible with well materials, rock, and reservoir fluids. All wells that penetrate the confining layer within a specified or calculated AoR or zone of endangering

Table 8. Siting and Construction Requirements for Class I and II Injection Wells

Class I (hazardous)	Class I (nonhazardous)	Class II
<p><i>Siting</i></p> <ul style="list-style-type: none"> • 2-mile area of review (AoR) study performed. • No-migration petition demonstration required. • Sited in demonstrated geologically stable area. • Additional geological structural and seismicity studies performed. <p><i>Construction</i></p> <ul style="list-style-type: none"> • Well is cased and cemented to prevent movement of fluids into USDWs. • Detailed requirements for appropriate tubing and packer. • UIC program director must approve casing, cement, tubing, and packer design prior to construction. 	<p><i>Siting</i></p> <ul style="list-style-type: none"> • Minimum of ¼-mile AoR study performed. • Sited in demonstrated geologically stable area. <p><i>Construction</i></p> <ul style="list-style-type: none"> • Well is cased and cemented to prevent movement of fluids into USDWs. • Constructed with tubing and packer appropriate for injected wastewater. 	<p><i>Siting</i></p> <ul style="list-style-type: none"> • Minimum of ¼-mile AoR study performed. <p><i>Construction</i></p> <ul style="list-style-type: none"> • Well is cased and cemented to prevent movement of fluids into USDWs. • Construction and design of well (casing, tubing, and packer) varies.

influence must be identified and properly plugged or completed, demonstrating that all potential pathways for migration have been addressed (a minimum of a ¼-mile AoR study is required for both nonhazardous Class I injection wells and Class II injection wells).

In addition to extensive geological and AoR studies, operators of Class I hazardous injection wells must demonstrate with reasonable certainty that the hazardous components of their wastewaters will not migrate from the injection zone. To comply with this requirement, operators must demonstrate through predictive models that the hazardous waste will not migrate from the injection zone for at least 10,000 years or that attenuation, transformation, or immobilization will render wastes nonhazardous before they

migrate from the storage reservoir. Preparation of a no-migration petition is a lengthy and costly process, typically requiring up to 11,000 hours and costing in excess of \$2 million (U.S. EPA, 2001). No other UIC well classifications specify containment time for injected wastes.

Class I and II injection wells require casing and cementing adequate to prevent movement of fluids into or between USDWs. All Class I injection wells must be constructed with corrosion-resistant materials that are compatible with the injectate and formation rock and fluids or any material in which it comes in contact with (40 CFR 146.65).

Construction requirements for Class II injection wells vary, but will be designed to last the life of the well.

Operation and Monitoring (Classes I, II, and V)
 Table 9 provides a summary of federal regulatory requirements for operation and monitoring of Class I (hazardous and nonhazardous) and Class II injection wells. Monitoring requirements for use of a Class V injection well are stipulated by the state enforcing agency or EPA based on well operation. States and EPA can require a Class V well operator to obtain a permit, monitor injectate, or close the well in the event of fluid migration to a USDW or if there is potential for USDW endangerment.

With the exception of Class I hazardous injection wells, there are no federal requirements for monitoring plume migration to overlying formations, and while this monitoring can be, it is rarely specifically mandated for Class I hazardous injection operations (Wilson et al., 2003). While the implementation of new monitoring wells is approved to supplement monitoring requirements and provide evidence of plume migration, it is rarely required because of the increased risk it poses to contaminant migration, a

Table 9. Operation and Monitoring Requirements for Class I and II Injection Wells

Class I (hazardous)	Class I (nonhazardous)	Class II
<ul style="list-style-type: none"> Continuously monitor injection pressure, flow rate, volume, temperature, and annulus pressure. Monitor fluid chemistry and groundwater as needed. Install alarms and devices that shut in the well if approved injection parameters are exceeded. Maintain injection at pressures that will not initiate new fractures or propagate existing fractures. Follow approved waste analysis plan. Conduct internal mechanical integrity testing (MIT) every year and external MIT every 5 years. Monitoring wells to supplement required monitoring are authorized. 	<ul style="list-style-type: none"> Continuously monitor injection pressure, flow rate, volume, and annulus pressure. Monitor fluid chemistry. Conduct yearly pressure falloff test. Maintain injection at pressures that will not initiate new fractures or propagate existing fractures. Conduct internal and external MITs every 5 years. Monitoring wells to supplement required monitoring are authorized. 	<ul style="list-style-type: none"> Monitor injection pressure, flow rate, and cumulative volume (observed weekly for disposal and monthly for enhanced recovery; continuous monitoring required in specific situations). Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well. Maintain injection at pressures that will not initiate new fractures or propagate existing fractures. Conduct internal and external MITs every 5 years. Monitoring wells to supplement required monitoring are authorized.

consequence of the invasive nature of the technique. At odds with this line of reasoning is the argument against monitoring wells based on the notion that most potential leakage pathways are concentrated in or around the injection well and that even if there is a relatively high-permeability leakage path in the confining layer some distance from the injection well, the reservoir pressure would not be sufficient to cause large leakage (Miller et al., 1986). Additionally, it may be argued that randomly placed monitoring wells have a statistically low probability of success; therefore, implementation is warranted only when placement can be based on the identification of a potential leakage pathway (Warner, 1992).

Record Keeping and Reporting Requirements (Classes I, II, and V)

Results of required monitoring and testing

must be submitted to the state or EPA UIC Director for all Class I and II injection well operations. In states with UIC regulatory authority, the Regional Administrator may require operators to submit additional information as needed to determine if a well poses a hazard to a USDW. Table 10 provides a summary of the federal reporting requirements for Class I and II injection wells. Reporting and record keeping is required for all permitted Class V injection wells, although requirements differ depending on well status and location.

Closure and Abandonment Requirements (Classes I, II, and V)

Federal regulations for closure and abandonment require that Class I and II injection wells be plugged with cement in a manner that will not allow the movement of fluids either into or between USDWs.

Table 10. Reporting and Record-Keeping Requirements for Class I and II Injection Wells

Class I (hazardous)	Class I (nonhazardous)	Class II
<ul style="list-style-type: none"> • Report quarterly on injection and injected fluids and monitoring of USDWs in the AoR, results from the waste analysis program, and geochemical compatibility. • Report on internal MIT every year and external MIT every 5 years. • Report any changes to the facility, progress in meeting the milestones of a compliance schedule, loss of mechanical integrity (MI), or noncompliance with permit conditions. 	<ul style="list-style-type: none"> • Report quarterly on injection and injected fluids and monitoring of USDWs in the AoR. • Report every 5 years on internal and external MITs. • Report any changes to the facility, progress in meeting the milestones of a compliance schedule, loss of MI, or noncompliance with permit conditions. 	<ul style="list-style-type: none"> • Submit an annual disposal/injection well-monitoring report summarizing observations of injection pressure and cumulative volume (may be conducted on a field or project basis). • Report every 5 years on internal and external MITs. • Report any noncompliance with UIC regulations.

More stringent requirements are placed on Class I hazardous and nonhazardous injection wells including tagging and testing each cement plug and continuing groundwater monitoring until there is no potential for influencing a USDW (hazardous wells only). Table 11 summarizes closure requirements for Class I and II injection wells. Federal regulations for Class V injection well closure require only that the operator close the well in a manner that prevents the movement of fluid into a USDW.

Natural Gas Storage

The practice of underground injection and storage of natural gas provides an excellent analog to CO₂ sequestration, perhaps providing more direct relevance to CO₂ storage than the underground disposal of liquid wastes, given the buoyant properties of both CO₂ and natural gas. A number of factors are critical to the successful storage of both natural gas and CO₂, including:

- Adequate site characterization, including permeability thickness and extent of storage reservoir, caprock integrity, geological structure, and lithology.
- Deep injection to allow sufficiently high gas pressures for economic success of gas storage (in CO₂ storage, deep injection is favorable to keep CO₂ in a dense supercritical phase, allowing for better use of reservoir capacity).
- Proper design, construction, monitoring, and maintenance of injection wells.
- Proper operation and monitoring to prevent overpressuring of the storage reservoir.
- Proper plugging of abandoned wells within the AoR.

Table 11. Closure and Abandonment Requirements for Class I and II Injection Wells

Class I (hazardous)	Class I (nonhazardous)	Class II
<ul style="list-style-type: none"> • Flush well with nonreactive fluid; tag and test each cement plug. • Conduct pressure falloff test and MIT. • Submit plugging and abandonment report. • Complete outstanding cleanup actions; continue groundwater monitoring until injection zone pressure cannot influence USDW. • Inform authorities of the well, its location, and zone of influence. 	<ul style="list-style-type: none"> • Flush well with nonreactive fluid; tag and test each cement plug. • Submit plugging and abandonment report. 	<ul style="list-style-type: none"> • Submit plugging and abandonment report

The primary regulatory authority for protecting the environment and USDWs from adverse effects of underground natural gas storage resides with each state. While regulations differ, effective requirements for permitting, operating, and monitoring have been established to ensure the safe and effective storage of natural gas. In general, regulations provide rules and guidelines for proper site selection and characterization, well construction, testing, monitoring, and reporting. In addition to regulatory requirements, economic incentives encourage effective storage.

According to the American Gas Association (1999), as of 1998, there were 466 underground natural gas storage projects in the United States and Canada, utilizing depleted gas and oil reservoirs, mined salt caverns, and aquifers, with 33 projects within six states and one province in the PCOR Partnership region. Non-oil- and gas-producing states within the PCOR Partnership region that do have experience with underground natural gas storage may determine that the regulatory framework for natural gas storage provides a more direct analog for regulating CO₂ storage than the current UIC framework.

The National Environmental Policy Act

The National Environmental Policy Act (NEPA) of 1969 establishes national environmental policies that pertain to the federal government as a whole and stipulates certain procedural requirements for federal agency actions. Except as otherwise provided by Congress, the Act applies to all federal agency actions. This includes actions that intersect with private activities, for example, through a federal permit or funding. However, the requirements may vary depending on the type of action involved. NEPA establishes goals for agency actions as well as the requirement to prepare environmental documents.

Various levels of analysis of potential environmental effects, depending on the circumstances and the expected degree of environmental impacts, are required by the regulations. Generally, an environmental impact statement (EIS) must be prepared for major federal actions that significantly affect the environment. An EIS must review a sufficient assortment of proposed alternatives and the direct, indirect, and cumulative effects or impacts of each alternative.

An agency is excluded from preparation of any formal NEPA environmental analysis with respect to activities that are either separately or cumulatively known to have no or only minor environmental effects. These activities are known as categorical exclusions. Most federal agencies have developed criteria for defining and listing actions that may be categorical exclusions. However, these activities are subject to being removed from the listing if particular circumstances, for example, the presence of wetlands or species listed as threatened or endangered, are present.

An environmental assessment (EA) is a midlevel analysis prepared for an activity that is not clearly categorically excluded but does not clearly require an EIS. Based on the EA, the agency either prepares an EIS or issues a "Finding of No Significant Impact" (FONSI), which averts further NEPA study and document preparation. In order to make a valuable contribution, an EA should be prepared early in the decision-making process of a particular action.

Long-Term Management and Liability Issues

The viability of carbon sequestration could be greatly affected by how the regulatory structure defines responsibilities for long-term management and liability. Private entities may be deterred from pursuing carbon sequestration if a liability structure is in place that imposes considerable costs with uncertain risks. On the other hand, a

liability regime could be developed that would encourage private investment in sequestration options by decreasing their private risk and increasing market penetration (Figueiredo et al., 2003).

Liability for geological carbon sequestration is derived from three key sources: liability from operational impacts, liability from in situ risks, and liability associated with variations from the goal of permanent storage. Liability from in situ risks includes formation leaks to the surface, migration of carbon dioxide within the formation, and seismic events. These risks may have an impact on public health and the environment. There also exists a liability related to future carbon regimes and how to account for any leakage from storage reservoirs (Figueiredo et al., 2003). Current state and federal liability structures for oil and gas production, natural gas storage, radon exposure, low-level radioactive waste (LLRW) storage and disposal, and hazardous waste storage and disposal may provide some guidance for CO₂ sequestration. In addition, the transportation and injection of carbon dioxide for EOR operations have been commonplace in oil and gas production for decades, and the liability associated with operational impacts is managed today. The level of rigidity varies across regulatory analogs.

The current liability structures for oil and gas production and natural gas storage may provide the most acceptable approach for encouraging the development of long-term CO₂ storage projects as they are typically based on the notion that public benefits outweigh the potential risks. Under the current regulatory framework for EOR, some states require that the last operator of an EOR project assume liability following final closure of the project. In most oil- and gas-producing states, where a responsible party cannot be established by regulation or is no longer in business,

the state government assumes responsibility.

In the case of radon exposure, no specific regulations govern liability for radon in one's home. However, courts have historically used principles of implied warranty of habitability, meaning the buyer assumes the dwelling is habitable at the time of purchase and assumes strict liability.

LLRW storage and disposal demonstrates a liability structure that discourages storage. The LLRW Policy Act, as amended in 1985, dictates that states are responsible for wastes generated within their borders (42 USC 2021b). The unintended effect of this regulatory framework has been that no new LLRW facilities have been built, largely because no state regulatory authority will approve a disposal facility within its borders (U.S. GAO, 1999).

The requirements for storage and disposal of hazardous waste represent the most stringent liability regime. As part of the CERCLA, cleanup costs are funded through a Hazardous Substance Response Trust Fund that, historically, has been replenished by potentially responsible parties, including current owners and operators, prior owners and operators at the time of disposal, generators of hazardous waste, transporters of hazardous waste, and even entities that arranged for transportation (Menell, 1991).

While long-term liability is nothing new, the regulatory frameworks that will address CO₂ storage must be evaluated or revised to ensure they meet the long-term goals of carbon sequestration.

Canadian Regulatory Framework

A number of provincial and federal laws and regulations have application to CO₂ capture and storage. The following sections briefly review these laws as they relate to potential CO₂ storage activities in the

PCOR Partnership's three Canadian providences. All information contained in the following sections was generously provided by Dr. Malcolm Wilson of the Office of Energy and Environment of the University of Regina and Clifton Associates Ltd., of Regina, Saskatchewan, as developed for the governments of Canada, British Columbia, Saskatchewan, and Alberta (Parsons et al., 2004).

In general, activities which impact natural resources and the environment are under provincial jurisdiction, with the federal government only presiding over international and transboundary issues (e.g., between Canada and the United States or between provinces); territories (Nunavut, Northwest and Yukon), which are administered by the federal government; and marine territorial waters. While the federal Canadian Environmental Protection Act covers atmospheric emissions of hazardous and/or toxic substances, CO₂ is not currently classified as such. Deep well injection activities and the protection of groundwater are under provincial jurisdiction unless interprovincial or international boundaries are crossed, in which case, the federal government also has jurisdiction. Typically, air and groundwater protection fall under the mandate of provincial Environment Departments, while deep well injection falls under the mandate of provincial oil and gas regulatory agencies.

CO₂ Capture

CO₂ capture activities are regulated through specific codes of conduct related to the movement and transportation of CO₂. These regulations are considered adequate for a newly emergent CO₂ capture industry; however, they may require further evaluation in relation to the unique properties of CO₂, long-term exposure to materials, and the high volume of CO₂ processed for storage activities.

Current laws, guidelines, and standards for human and environmental health have been developed in the context of short-term exposure to relatively small volumes of CO₂. Review of these guidelines in the context of both longer-term environmental exposure and any specific occupational health and safety requirements associated with exposure to higher concentrations of CO₂ is necessary to ensure safe operations.

Pipeline Transportation

Onshore pipeline transportation of CO₂ within provincial boundaries is regulated by provincial agencies while pipeline transmission of CO₂ across provincial or international boundaries or within the Canadian territories is regulated by the National Energy Board under the Onshore Pipelines Regulations. These regulations set out technical and safety requirements for all aspects of a pipeline's life cycle. Any incidents concerning pipelines are reported to the Transportation Safety Board.

Provincial and federal acts and regulations related to pipeline transportation are included in Appendix C.

Existing rules and practices for CO₂ transport appear to be adequate for CO₂ capture and storage projects. The transportation of dense-phase CO₂ has been practiced for at least 30 years and now is incorporated into steel pipeline standards. Further development of the standards may be required to accommodate higher volumes of CO₂ and potential implications of pipeline leaks.

CO₂ Injection and Storage

Standards and procedures for injection wells have been developed around safe practices required for drilling, closure, and abandonment of oil and gas, sour gas, sulfur, and/or water wells. The infrastructure used for CO₂ flooding, including injection wells, is the same as that used for primary and secondary recovery phases of oil production. There

are currently no well construction and abandonment practices specific to CO₂ injection facilities. In most cases, minimal construction requirements are set to protect nonsaline sources of groundwater from contamination. Abandonment regulations in oil and gas production operations require the operator to submit a plugging and abandonment plan as part of the permit application, identifying the number and method of placement of plugs in the well. The operator must also demonstrate financial capability for proper abandonment. The current regulatory framework does not consider the abandonment of injection wells in the context of continuing use. In general, abandonment procedures for oil and gas wells protect against surface and geomorphological damage, but do not necessarily ensure the integrity of any underground reservoirs.

Existing regulations related to underground storage were developed primarily for petroleum and natural gas and have no provisions in place for the storage of CO₂. While natural gas storage regulations may provide regulatory guidance for CO₂ storage projects, they were never intended for the type of long-term storage required for effective CO₂ sequestration. Acid gas injection (mixture of H₂S and CO₂) into deep aquifers and depleted oil and gas reservoirs has been conducted since 1990 at more than 40 sites in the provinces of Alberta and British Columbia and may provide the best guidance for understanding and regulating CO₂ storage. Procedures for permitting and monitoring acid gas injection operation have been developed by the Alberta Energy and Utilities Board and by the British Columbia Oil & Gas Commission. Refer to Appendix C for further regulatory information relating to CO₂ injection and storage in PCOR Partnership provinces.

MM&V

While regulatory requirements for MM&V of CO₂ storage may be adapted from existing regulations for enhanced-recovery operations, natural gas storage, and waste disposal, they do not adequately address the needs for verifying the safe and effective long-term storage of CO₂. Current logging and testing requirements for waste disposal injection wells include 1) continuous monitoring of injection flow rates and pressures; 2) annual monitoring using radioactive tracer logging, annulus pressure testing, and reservoir testing; 3) temperature logging, casing inspection logging, and cement bond logging conducted every 5 years; and 4) mechanical integrity testing for well abandonment. Current regulations for waste injection do not require separate monitoring wells. Methods developed by the oil and gas industry, including injection well pressure monitoring and 3-D seismic surveys, may be used to verify storage efficiency and provide early warning in the event of failure. However, more site-specific studies are needed to adequately demonstrate their sensitivity and to develop standard MM&V protocols. Appendix C includes additional provincial regulatory requirements related to monitoring and measurement of injection.

Mitigation of Risk

Provincial and federal environmental assessment and protection acts as well as occupational health and safety acts aim to protect human and environmental health (Appendix C). Both provincial and federal acts might be expected to have application in CO₂ sequestration projects because of the provincial location of the storage reservoir and the federal interest in reducing CO₂ emissions to the atmosphere.

Liability and Long-Term Management

Financing provisions for emergency responses in the event of escape, remediation in the event of failure, and compensation for lands, crops, animals

and people that might be affected by escape are provided for in government bonding requirements associated with environmental protection, oil and gas, and mining legislation. While similar provisions could be developed for CO₂ storage, they would require modification to accommodate the longer time periods involved in sequestration projects.

Provisions for management capacity in the present scope of potentially applicable laws, regulations, and codes of conduct address matters of due diligence and capacity to meet the conditions of license. Because of the long life of a CO₂ storage project and the requirement for competent and professional management, provisions must address the long-term management of the project. At present, no standards or regulations address this long-term management requirement nor the capacity of the organizational structure to provide for management.

Considerations in Developing a Regulatory Framework for Long-Term Storage

The following sections address potential needs for regulatory oversight in CO₂ storage operations, gaps in the current regulatory framework, and uncertainties. To limit the complexity required in regulatory development of CO₂ sequestration, all suggestions are based on the assumption that a regulatory framework must effectively account for CO₂ removed from the atmosphere.

Definition

At the present time, there is no consistent regulatory definition of CO₂. While high-purity CO₂ is generally defined as a commodity in industrial operations, in a carbon-constrained regulatory environment, it is possible that CO₂ could be defined as a GHG pollutant or waste product. If regulatory requirements increase based on the regulatory definition of the product, geological storage opportunities may be greatly restricted.

The IOGCC CO₂ Geological Task Force has made the following recommendation in its Final Report to DOE:

“Existing federal air regulations do not define CO₂ as a pollutant. There is no need for state regulation to do otherwise. However, states which may have already defined CO₂ as a waste, air contaminant, or pollutant may be advised to reassess that definition so as to not negatively impact carbon capture and geological storage (CCGS) development. While contaminants and pollutants such as NO₂, SO₂, and other emission stream constituents should remain regulated for public health and safety and other environmental considerations, CO₂ is generally considered safe and nontoxic and is not now classified at the federal level as a pollutant/waste/contaminant and should continue to be viewed as a commodity following removal from regulated emission streams.”

Capture and Transport

Several concerns relate to the capture and pipeline transport of CO₂, including:

- Compatibility of dense-phase gas with engineered systems and formation (relating to purity or gas composition).
- Health and safety issues pertaining to gas composition.
- Pipeline access (there is a potential need for new eminent domain/condemnation laws for CO₂ pipelines) and the notion of “common carrier” status.
- Variability in gas composition from different sources (poses concern for transportation via common pipelines and reservoir injection that rely on multiple sources).

The IOGCC CO₂ Geological Task Force has concluded in its Final Report to DOE that given the substantial regulatory framework that currently addresses emission standards, there is little need for state regulatory frameworks in this area. Specific recommendations set forth by the task force include the following:

- Require clarity and transparency in any potential statute and regulation development.
- Devise standards for measurement of CO₂ concentration at the capture point to verify quality necessary for conformance with CCGS requirements.
- For transportation of CO₂ by pipeline, utilize regulatory structures from existing DOT, OPS, and state rules and regulations governing CO₂ pipeline construction, operation, maintenance, emergency responses, and reporting.
- Include CO₂ in the state's "call before you dig" protocol.
- In development of state permitting procedures, identify areas of special concern such as heavily populated areas and environmentally sensitive areas so that additional safety requirements can be considered.
- While the "open access" issue is ultimately a federal concern, states must be aware of the relevancy of the open access issue as it affects state regulatory responsibilities.
- Review existing state eminent domain statutes to determine if CO₂ meets the requirements necessary to allow the use of state eminent domain authority for CO₂ pipeline construction. Clarify state eminent

domain powers affecting the construction of new CO₂ pipelines while respecting private property rights.

- Identify opportunities for use of existing rights of way, both pipeline and electric transmission, for transportation of CO₂.
- Allow for CO₂ transportation in preexisting pipelines used to transport other commodities, providing that safety, health, and environmental concerns are addressed.
- Involve all stakeholders, including the public, in the rule-making process at the earliest possible time.

Site Selection

Proper siting is critical to the success of long-term storage operations.

Considerations for site selection may include, but not be limited to, the following:

- Injection depth (typically greater than 800 m for dense-phase CO₂ flooding); although this may not be necessary for storage, it is worth noting that the leakage potential may be reduced with increased density.
- Regional seismicity, stresses, and strains.
- Caprock integrity – may require geophysical surveying, including a detailed 3-D seismic profile; coring for geomechanical, geochemical, porosity, and permeability testing; pressure testing and geochemical analysis of fluids above and below the caprock and evaluation of the nature of the sediments between the

top of the caprock and the base of the vadose zone.

- Storage capacity.
- Proximity to USDWs.
- Potential pathways of leakage including abandoned wells, faults, and fractures.
- Undeveloped mineral or hydrocarbon resources.
- Proximity to populated areas.
- Present and future use of adjacent properties including subsurface activities.
- Topography.
- Environmental justice.

In the near term, it is anticipated that CO₂ sequestration activities will largely be conducted in conjunction with enhanced oil and gas recovery projects. As the need for greenhouse gas offsets increases, CO₂ storage in deep saline formations will become more attractive, given the potential storage capacity of such reservoirs. The current uncertainty of storage efficiency and ecological health associated with utilization of deep saline reservoirs may require unique site characterization strategies different than those that may be required for already well-characterized oil and gas reservoirs.

Injection

Because of the lack of regulatory uniformity in underground injection across the United States, if bound by current rules for injection, similar projects for geological sequestration of CO₂ could easily be subjected to very different requirements, which, in some cases, could be prohibitive to project implementation.

The PCOR Partnership region provides a prime example of such variability in underground injection regulation. Under the UIC Program, underground injection of CO₂ in the PCOR Partnership region falls under multiple jurisdictions, according to state and provincial authority and formation type and may be subject to less stringent Class II injection well requirements in some states, while subject to Class I permitting in others. In general, requirements should ensure that injection does not induce fracturing, faulting, or displacement of reservoir fluids and gases out of the storage reservoir or provide a leakage pathway along the injection wellbore. Existing regulations need to be reviewed to determine if they adequately address the unique properties of CO₂. It is a worthwhile consideration to evaluate potential frameworks that might facilitate transition of existing Class II EOR wells to more permanent usage for long-term CO₂ storage.

IOGCC CO₂ Geological Sequestration Task Force recommendations for regulating injection include the following:

- Require clarity and transparency in all statute and regulation development.
- States with Oil and Natural Gas Conservation Acts and with existing CO₂ injection related to EOR projects or future ECBM and enhanced gas recovery (EGR) currently regulate these projects under UIC programs. These existing regulatory frameworks provide a successful analog for CCGS and should be examined as to whether they will adequately address the unique properties of CCGS in depleted oil and natural gas reservoirs dealing with well construction, casing, cementing, and well abandonment. To the extent necessary, these statutes and

regulations should be modified to include geological storage as suggested in the IOGCC Model Conservation Act. States without experience in CO₂ EOR can look to those states with ongoing CO₂ EOR projects whose statutes and regulations have proven to be successful.

- States and provinces with natural gas storage statutes should utilize their existing natural gas regulatory frameworks, with appropriate modifications, for CCGS. Those states without experience can look to the referenced conceptual framework of other states whose regulations have proven successful. Should EPA recommend that injection of CO₂ for non-EOR purposes be regulated under the UIC program, the Task Force strongly recommends reclassifying such wells either as a subclass of Class II or a new classification. The Task Force strongly believes that inclusion of non-EOR CCGS wells under Class I or Class V of the UIC program would not be appropriate.
 - States and provinces with regulations for acid gas injection should utilize their regulatory frameworks, with appropriate modifications, for CCGS.
- Regulations governing permitting processes should adequately address reservoir properties relative to the interaction of CO₂ with rock matrix and reservoir fluids. For example, carbonate precipitation is an unknown factor where there is CO₂ exposure within the reservoir over a long period of time. Further study is needed to define this issue.
- Well and equipment operational regulations should take into account the unique properties of CO₂. For example, CO₂, when exposed to water, forms carbonic acid, which is corrosive to oil field equipment and cement. Further study is needed to define the scope of the issue from the standpoint of standards and regulations.
- Regulations governing permitting processes for non-EOR CO₂ injection projects should respect existing property rights dictated by state law in issuing CO₂ storage site permits.
- Existing monitoring regulations currently in use for CO₂ EOR, natural gas storage, and acid gas injection may not adequately address monitoring and verification requirements for CO₂ storage to ensure injected CO₂ is accounted for. These regulations will need to be amended to ensure that the CCGS is performing as expected relative to safely storing CO₂ away from the atmosphere, accounting for those volumes, and establishing leak detection protocols.
- Review existing CO₂ EOR, natural gas storage, and acid gas regulations to ensure that operational plans for addressing public health and safety, as well as release or leakage mitigation procedures, are adequate.
- Adapt and modify established permitting regulations and standards for site characterization for purposes of CCGS. Consider results of DOE-sponsored partnership research and other ongoing research.

- Involve all stakeholders, including the public, in the rule-making process at the earliest possible time.

Monitoring and Verification

Monitoring and mitigation plans are crucial for ensuring the safe and effective long-term storage of CO₂. Under the current UIC Program, there are limited requirements for monitoring and verification. Even under the stringent framework for Class I injection wells, there are no federal requirements for monitoring actual migration of fluids within the injection zone, nor are there requirements for monitoring in overlying zones to detect leakage, with the exception of Class I hazardous wells (Wilson et al., 2003). The verification of CO₂ storage is relatively straightforward, assuming one can accurately measure the volume of CO₂ injected into and released from the storage reservoir. Unfortunately, verification of efficiency is not that simple. Technical limitations and the extended lifetime of a storage project will make it difficult to adequately assess the effectiveness of sequestration. From a health and safety perspective, verification poses less of a concern, provided that projects identify and carefully monitor areas of high risk. For accounting purposes, standard monitoring and estimation techniques must be developed and accepted for assessing leakage. Broad-scale monitoring and predictive modeling will likely be required if verification is mandated.

Mitigation and Remediation

The regulatory framework developed for geological storage of CO₂ must establish a threshold for acceptable reservoir leakage after which mitigation or remediation procedures would be required. Given the variability of risks across a diversity of sequestration scenarios, establishing a standard threshold of acceptable leakage may prove difficult. For this reason, regulatory requirements may need to be

tailored to specific storage projects according to associated risks.

Long-Term Management and Liability

The regulatory framework for CO₂ sequestration must adequately address long-term liability and responsibility. Given the long timescales involved in geological storage, it is unreasonable to expect liability to rest solely with the private sector. To ensure adequate long-term management practices, including emergency response, remediation, and compensation for damages in the event of failure postinjection, and site closure, government oversight is necessary. Such government assurance could be provided through government administration of industry-funded programs. Both financial considerations and transfer of liability for long-term management must be addressed in the near term. If there are no clear methods for transferring financial responsibility, private entities will be reluctant to commit resources to geological storage even if constrained to do so under requirements for lowering emissions.

First-party insurance, direct government regulation coupled with insurance, payments out of the tax system, liability caps, or a system of guaranteed benefits are some possible alternatives that might resolve the liability situation. If it becomes possible to estimate risk, first-party insurance could be used. Direct government regulation, coupled with insurance, is another option, with the insurance being first-party, compulsory, or government-provided. If government wants to assume full liability for an accident, payments out of the tax system could be used. Liability caps, similar to what is done for high-level radioactive waste, would make companies liable for accidents, but only up to a specified amount. Finally, a framework could be developed that provides a schedule of guaranteed benefits in the case of leakage.

The IOGCC CO₂ Geological Sequestration Task Force has recommended the following in its Final Report to DOE for regulating postinjection storage:

- Require clarity and transparency in all statute and regulation development.
- Consider the potential need for legislation to clarify and address the unknown issues that may arise in the ownership of storage rights (reservoir pore space) and payment for use of those storage rights.
- Research the chemical transformations that are likely to take place in the reservoirs over long periods of time which may impact, positively or negatively, reservoir integrity in CO₂ storage time frames. Some work has already been done in this area.
- Construct a regulatory framework for the storage stage that allows for the potential of future removal of CO₂ for commercial purposes.
- Given the long time frames proposed for CO₂ storage projects, innovative solutions to protect against orphaned sites will need to be developed. The current model utilized by most oil- and natural gas-producing states and provinces—whereby the government provides for ultimate assurance in dealing with orphaned oil and natural gas sites—may provide the only workable solution to this issue. This can be accomplished through state and provincial government administration of federally guaranteed industry-funded abandonment programs.

- Establish technical standards for well abandonment and site closure accounting for specialized concerns dealing with the unique properties of CO₂ impacts on reservoir characteristics, well construction, and cementing techniques normally used in the oil and natural gas industry.
- Establish procedures for long-term reservoir management and monitoring. A new framework will need to be established to address the long-term monitoring and verification of emplaced CO₂ to confirm that injected volumes remain in place.
- Establish a regulatory threshold requiring mitigation procedures to be initiated.
- Involve all stakeholders, including the public, in the rule-making process at the earliest possible time.

Procedural vs. Performance-Based Regulations

The current regulatory framework for underground injection is almost exclusively procedural rather than performance-based, meaning that regulations specify detailed procedures that must be followed rather than specify a desired outcome and allow for flexibility in how goals are met. The advantages to performance-based regulations include economic efficiency and flexibility. The drawbacks to this type of regulation are that compliance ultimately rests on the ability to infer performance from parameters that can be directly measured. For geological sequestration, a performance-based outcome would have to quantitatively specify storage efficiency, likely in terms of leakage rate over the lifetime of the project. Given that sequestration projects are expected to effectively store CO₂ for centuries and that

there are technical limitations to direct measurement of leakage, this parameter, at best, would have to be inferred through modeling or potentially costly monitoring practices, which would likely be defined by specific guidelines.

Although it is problematic, performance-based regulation is used in both hazardous waste injection and storage of radioactive wastes. While there have been few reported problems, it is difficult to assess the success of such projects because little monitoring has been done to validate modeling predictions. It is important to note that monitoring activities at Weyburn and Sleipner West are already more advanced than comparable studies for monitoring the migration of hazardous wastes underground. What form regulations assume for the management of geological sequestration is uncertain. At the present time, however, there is no consensus on an acceptable storage lifetime—a crucial element of the performance outcome.

It is not yet clear if geological CO₂ sequestration will be integrated into the current regulatory framework or if a new approach will be developed. It is well recognized, however, that if some standardization is not accepted, the future for geological sequestration may be limited to the point that it will be an ineffective means for reaching long-term goals for reduced atmospheric concentrations of CO₂. The difficulty in building a system for regulating CO₂ will not simply be due to technical uncertainty in predicting the safety and effectiveness of CO₂ storage, but also to uncertainty in the political and regulatory goals of geological sequestration. For instance, what is the long-term goal of CO₂ sequestration, and what quantity of CO₂ must be effectively stored to reach that goal? Should the median lifetime of CO₂ storage be 500 years or 10,000 years? What rate of failures are we willing to accept?

Agreement must be reached on these issues to drive the geological sequestration agenda, determine the appropriateness of individual technologies, and effectively shape the needed regulatory framework.

CONCLUSIONS

To ensure the safe and effective terrestrial and geological storage of CO₂, projects must identify and evaluate potential ecological and environmental impacts, effectively monitor and assess storage efficiency, and be prepared to take remedial action in the event of failure. The risks associated with CO₂ sequestration are typically divided into two categories: 1) local environmental impacts including risks to the environment and human health and safety and 2) global atmospheric impacts arising from leaks that return stored CO₂ to the atmosphere. While low levels of CO₂ are essential for life, elevated concentrations of CO₂ in shallow subsurface soils or overlying air can adversely affect local ecology, including humans. Elevated atmospheric concentrations of CO₂ may influence the global climate.

What is known to date concerning risks of CO₂ sequestration include the following:

- CO₂ can be safely stored in geological formations over long periods of time as observed with naturally existing CO₂ reservoirs.
- Environmental and ecological health effects are well understood.
- The largest risks of CO₂ capture and storage have been identified.
- Local hazards are generally more dependent on the nature of the release than the size of the release.

- CO₂ poses no health and safety risk at low concentrations.
- CO₂ is not flammable or explosive but does react with water.
- CO₂ is denser than air and has the potential to pool in low-lying areas or poorly ventilated spaces.

To limit risks of geological sequestration, close MM&V will be required through all phases of CO₂ sequestration, including capture and separation, transportation, injection, and long-term storage. The implementation of MM&V serves several purposes, including 1) protecting worker health and safety; 2) ensuring environmental and ecological safety; 3) verifying safe and effective storage, including providing assurances of carbon credits or transactions in a carbon-trading market; 4) tracking plume migration; 5) providing early warning for failure; and 6) confirming model predictions. The primary elements associated with the MM&V of CO₂ sequestration can be divided into two categories: 1) the careful monitoring of engineered systems and 2) monitoring of migration of CO₂ within and out of the primary storage reservoir.

Whether geological CO₂ sequestration is integrated into the current regulatory framework or a new approach is developed, it is well recognized that if some standardization is not accepted, the future for geological sequestration may be limited to the point that it will be an ineffective means for reaching long-term goals for reduced atmospheric concentrations of CO₂. The development of a regulatory framework, based on science and designed with the flexibility required to encourage a reduction in CO₂ emissions, while providing protection for environmental and human health and verification of effective storage, will undoubtedly prove challenging (Forbes, 2002).

At this time, the demonstration and implementation of CO₂ sequestration are outpacing development of a regulatory structure for managing sequestration. Although there are challenges in establishing a regulatory framework for CO₂ storage, the issue has been recognized, and current research will only help to better define the needs. It must be noted, however, that the difficulty in developing an effective regulatory framework for long-term CO₂ storage is not simply a factor of technical uncertainty in predicting the lifetime of a given storage reservoir, but is instead closely tied to the uncertainty regarding what is required to effectively mitigate climate change (e.g., a clearly defined acceptable leakage rate).

An appropriate regulatory structure will not easily be established until we reach some rough consensus on acceptable leakage rates. The PCOR Partnership does have the advantage of having a great deal of experience and history in extractive operations. With recent advancements in monitoring CO₂ storage at the Weyburn Field in Saskatchewan, the PCOR Partnership region is poised for near-term demonstration of additional capture and storage opportunities.

This report was prepared to serve as a backbone for the development of project-specific strategies for MM&V and risk identification in both terrestrial and geological storage and identification of appropriate permitting requirements for future projects in the PCOR Partnership region. As development of potential sequestration projects is further explored in this region, more detailed information will be provided as part of a comprehensive action plan.

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For more information on this topic, contact:

Thea E. Reilkoff, EERC Research Engineer
(701) 777-5000; treilkoff@undeerc.org

Lisa S. Botnen, EERC Research Scientist
(701) 777-5144; lbotnen@undeerc.org

Edward N. Steadman, EERC Senior Research Advisor
(701) 777-5279; esteadman@undeerc.org

John A. Harju, EERC Associate Director for Research
(701) 777-5157; jharju@undeerc.org

Visit the PCOR Partnership Web site at www.undeerc.org/PCOR.

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APPENDIX A

GEOLOGIC VARIABLES AND THEIR ASSOCIATED UNCERTAINTIES

Table A1. Geologic Variables and Their Associated Uncertainties (Friedmann, 2003)

Geological Target Type	Critical Uncertainty	Geological Variable 1	Geological Variable 2	Geological Variable 3
Depleted Oil and Gas Fields	Caprock integrity	Rock type (composition, permeability, strength)	Rock strength (thickness, burial history)	Effect of well perforations
	Total hydrocarbon solubility and miscibility Reservoir temperature and pressure		Hydrocarbon composition (e.g., API gravity)	Brine composition
Saline Formations	Injectivity at depth	Depth and thickness	High vs. low permeability and porosity	Reservoir complexity (sand percent, fractures)
	Total solubility	Brine salinity and pH	Reservoir pressure and temperature	Rock composition (clastic vs. carbonate, mineral storage potential)
	Risk of fast-path leakage	Density and offset of local faults	Trapping configuration (static vs. dynamic)	Caprock integrity
Unminable Coals	Porosity and permeability distribution	Cleat structure at depth	Matrix porosity vs. maximum burial depth	Variations with rank and composition
	Total adsorption	Rank and composition	Effects of other gases	Leakage risks

APPENDIX B

CODE OF FEDERAL REGULATIONS (CFR) RELATING TO CARBON DIOXIDE

Table B-1. Code of Federal Regulations (CFR) Relating to Carbon Dioxide (Benson et al., 2002)

CFR	Government Branch	Regulated As	Description	Regulation, limit/max.
9 CFR 313.5	FSIS, DOA	Anesthetic and asphyxiant	Humane slaughter of livestock	XX
14 CFR 25.831	FAA, DOT	Ventilation air contaminant	In airplane cabins	5000 ppm (0.5%) by volume
21 CFR 137.180, 137.185, 137.270	FDA, DHHS	Leavening agent	In self-rising cereal flours	Must exceed 5000 (0.5%)
21 CFR 184.1240	FDA, DHHS	Direct food substance	GRAS – generally recognized as safe	GRAS
21 CFR 201.161	FDA, DHHS	Medical drug	Exempt from labeling Requirements of 21 CFR 201.100	Exempt from Labeling
21 CFR 210-211	FDA, DHHS	Medical gas	Current good manufacturing practices (CGMP)	CGMP
21 CFR 582.1240	FDA, DHHS	General purpose food additive	GRAS – generally recognized as safe	GRAS
21 CFR 862.1160	FDA, DHHS	Clinical chemistry test system	Diagnostic of blood acid-base imbalance	
29 CFR 1910.134	OSHA, DOL	Compressed breathing gas	In respiratory protection equipment CGA and USP	CGA breathing air Grade D – 1000 ppm (0.1%)
29 CFR 1910.146	OSHA, DOL	Confined space hazard	General environmental controls	Permit required to enter
29 CFR 1910.155-1910.165 Subpart L	OSHA, DOL	Fire suppressant and confined space hazard	Required engineering controls on fire-fighting systems and equipment, employee training, and respiratory protection. NFPA	
29 CFR 1910.430	OSHA, DOL	Compressed breathing gas	Commercial diving operations – SCUBA	1000 ppm (0.1%)
29 CFR 1910.1000 Table Z-1	OSHA, DOL	Air contaminant	General occupational exposure limits	5000 ppm (0.5%) TWA PEL

Continued. . .

Table B-1. Code of Federal Regulations (CFR) Relating to Carbon Dioxide (Benson et al., 2002) (continued)

CFR	Government Branch	Regulated As	Description	Regulation, limit/max.
29 CFR 1915.1000 Table Z	OSHA, DOL	Air contaminant	Exposure limits for shipyard employment	5000 ppm (0.5%) TWA PEL
29 CFR 1926.55	OSHA, DOL	Air contaminant	Exposure limits for construction	ACGIH: 5000 ppm (0.5%) TWA TLV
30 CFR 56.5001	MSHA, DOL	Air contaminant	Exposure limits for surface mines	ACGIH: 5000 ppm (0.5%) TWA TLV
30 CFR 57.5001	MSHA, DOL	Air contaminant	Exposure limits for underground mines	ACGIH: 5000 ppm (0.5%) TWA TLV
40 CFR 180.1049	EPA	Pesticide, insecticide	Tolerance for pesticide chemical in food	Exempt from tolerance
42 CFR 84.79	NIOSH, PHS, DHHS	Compressed breathing gas	SCUBA	USP/NF, CGA: 1000 ppm (0.1%)
42 CFR 84.97	NIOSH, PHS, DHHS	Inspired air from SCUBA	Test of inspired air in SCUBA – control of rebreathing	>30 min/2.5%; 1 hr/2.0%; 2 hr/1.5%; 3 hr/1.0%; 4 hr/1.0%
42 CFR 84.141	NIOSH, PHS, DHHS	Compressed breathing gas	Supplied air respirators	CGA: 1000 ppm (0.1%)
46 CFR 197.340	Coast Guard, DOT	Compressed breathing gas	Commercial diving operations – SCUBA	1000 ppm (0.1%)
49 CFR 100-180	DOT	Transportation material	General transportation requirements	
49 CFR 190-199	OPS, DOT	Gas or hazardous liquid	Engineering safety controls on pipelines	

APPENDIX C

CO₂ CAPTURE AND STORAGE STATUTORY AND REGULATORY REVIEW – CANADA



**Annex A – CO₂ Capture and Storage
Statutory and Regulatory Review**



Annex A – CO₂ Capture and Storage Statutory and Regulatory Review

Introduction

This review was put together with the purpose of outlining some of the existing relevant Canadian legislation for storing carbon dioxide gas (CO₂) in a subsurface geological setting. Federal acts, as well as the provincial acts of British Columbia, Alberta, Saskatchewan, and Manitoba were consulted. Some relevant provincial regulations are also discussed to present a more complete picture. In the environmental assessment and protection section a very limited international review was also conducted for aspects related to the Kyoto Protocol but a complete review of relevant international laws, regulations, guidelines etc. is beyond the scope of this paper. Although many Canadian acts have some useful applications for developing future management strategies, no single act covers all areas relevant to the subsurface storage of CO₂. It is evident that there are gaps in the laws as they currently stand, when it comes to the implementation of a CO₂ capture and storage management system, and it is recommended that provisions need to be in place to cover these gaps. New legislation specifically designed for addressing the capture, transport, and subsurface storage of CO₂ needs to be drawn up in anticipation of the growth of this emerging industry.

Environmental Assessment and Protection

Both the federal government and the provincial governments of the four Western provinces have existing environmental assessment and environmental protection legislation in place. For the sake of this review, it is assumed that an environmental assessment would be carried out prior to the construction of any injection wells, pipelines, surface facilities, etc. Regardless of the project under consideration, environmental assessments are generally carried out in order to assess the associated risks prior to approval and before construction and drilling begins. In certain cases a development or project is undertaken *without* the submission of an environmental assessment to the responsible authorities. This practice is only acceptable when the project is included on an exclusion list, as is the case for certain projects in British Columbia, or when the Environment Minister of the given province deems the assessment as unnecessary.

Provincial

British Columbia

According to the Environmental Assessment Act of BC some projects are designated as “reviewable” (Sections 5 and 6). The minister may designate a project as reviewable if there is concern that it “may have a significant adverse environmental, economic, social, heritage or health effect, and that the designation is in the public interest” (Section 6). A CO₂ reservoir management system could qualify under this section since there are risks associated with leakage back to the surface through injection wells as well as uncertainty regarding migration back to the surface through soil, groundwater and bedrock. There is no mention made in the Reviewable Projects Regulation of any CO₂ capture or storage projects, however, it is safe to assume that such projects would fit the criteria for being “reviewable”.

The Environmental Impact Assessment Regulation outlines the information that must be included and risks that must be addressed for any project or development for which an environmental assessment act *is* required.

It might be argued that once an environmental assessment was submitted for *one* subsurface CO₂ storage project that any further environmental assessments for subsequent proposals would be identical, but this is not the case. The surficial and bedrock geology as well as the hydrogeology from one location to the next will differ and so the level of risk associated with migration back to the surface and groundwater contamination for each project would also differ. Public approval from one location to the next could also vary quite a bit. The costs of the environmental assessment (EA) process associated with subsurface storage projects for CO₂ gas may be a deterrent, but considering the reason why the projects are being considered in the first place (to reduce or offset greenhouse gas emissions) the EA is essential. A successful CO₂ storage project is only successful if it can be shown that the gas injected is staying there. Otherwise, the time and money invested in developing any subsurface management system is wasted. Any EA conducted should provide decision-makers with sufficient information to determine if the project will be successful and should proceed.



Alberta

In Alberta the governing statute is the Environmental Protection and Enhancement Act (EPEA). The Environmental Assessment (Mandatory and Exempted Activities) Regulation, which falls under this act, outlines the activities that constitute an environmental assessment and those that are exempt.

As with the other provincial assessment acts described in this review, there is no direct mention of CO₂. Included as one of the points in the purpose of the act is the recognition of the “principle of sustainable development, which ensures that the use of resources and the environment today does not impair prospects for their use by future generations” (Section 2). This is truly relevant in terms of subsurface storage. Effective legislation must be drawn up with the understanding that any laws put into place today must not only help us to reduce CO₂ emissions but they must also recognize our obligations to the future citizens of Canada. These laws or regulations will impact the future and due care should be taken in drawing them up.

According to the Alberta EPEA, the term “storage” means the holding of a substance or thing for a temporary period at the end of which it is processed, used, transported, treated or disposed of (Section 1). An expanded definition or alternative term would need to be added to the existing act in order to address the long term storage aspects required for CO₂.

It is clearly stated under Section 108 of Alberta’s EPEA that “No person shall knowingly release or permit the release of a substance into the environment in an amount, concentration or level or at a rate of release that is in excess of that expressly prescribed by an approval or the regulations.” This section leaves a margin of error for subsurface storage of CO₂ because acceptable rates of release or concentration levels at surface may be written into the regulations.

The Environment Minister of Alberta has certain powers to invoke changes which may carry some weight when it comes to developing a reservoir storage system for CO₂ in that province. For instance, “the Minister may develop other guidelines and objectives to meet goals or purposes toward which the Government’s environmental protection efforts are directed, including, without limitation, procedures, practices and methods for monitoring, analysis and predictive assessment” (Section 14(4)). In addition, the Minister may also establish emission trading, emission disposal fees, and subsidies in order to meet those goals and protect the environment (Section 12) and he or she may also make regulations respecting the payments which operators must make into any security funds and/or the insurance they must carry.

SASKATCHEWAN

There are several definitions that deserve some attention in the Environmental Assessment Act (EAA-SK) and The Environmental Management and Protection Act, 2002 (EMPA).

Carbon dioxide could be classified as a “contaminant” under the EAA-SK since the injection of this gas into a subsurface environment would be “in excess of the natural constituents of the environment”, affects the natural physical and chemical properties of the subsurface environment, and may be a danger to human and environmental health (Section 2) if any gas made its way back to the surface and the atmosphere. Subsurface storage of CO₂ qualifies as a development under the EAA-SK and no person can proceed with a development until the Minister has given his or her approval (Section 8(1)).

In the EMPA there is a definition for “person responsible for a discharge.” This definition is problematic for CO₂ because, according to the definition given in this act, the responsibility for any discharges at surface that resulted from subsurface storage would fall upon the collective shoulders of society. How then would fines for discharges be assigned under this act?

Unauthorized discharges are strictly prohibited under Section 4 of the EMPA: “No person shall discharge or allow the discharge of a substance into the environment in an amount, concentration or level or at a rate of release that may cause or is causing an adverse effect unless otherwise expressly authorized by an Act, Act of the Parliament of Canada, approval, permit, license, order or regulation.” The same principle applies in terms of discharges into drinking water supplies (Section 33) which would be applicable to safeguard against the potential contamination of groundwater by CO₂ migrating to the surface.

Under the EMPA (Section 81) the Lieutenant Governor in Council may make regulations: (r) regulating, restricting, prohibiting and requiring permits for discharge, containment, and storage or any substance relating to the mining industry; (x) respecting the closure or abandonment and the decommissioning and reclamation of any mining site; (xx) requiring operators to obtain

insurance or performance bonds. Although subsurface CO₂ storage projects might be better managed under existing oil and gas legislation, the general idea of Section 81 could easily be adopted into an act dealing specifically with carbon dioxide gas storage.



Manitoba

According to Section 1 of The Environment Act (EA) of Manitoba, subsurface storage of CO₂ would qualify as a development in the same way it qualifies under the EAA-SK of Saskatchewan. Injected carbon dioxide would qualify as a pollutant under the EA because it is foreign and in excess of the natural chemical quality of the subsurface environment (Section 1).

Under Section 41(1) of the EA, the "Lieutenant Governor in Council may make regulations (b) respecting the classification of certain geographic areas of the province by pollution assimilative capacity and the setting of ambient loading standards for those areas." This section is interesting as it could mean that certain areas in Manitoba could be classified in terms of ambient CO₂ levels at surface. This would allow for certain areas to be preferred locations for subsurface storage projects and their associated injection wells. Of course, ultimately it would be the subsurface properties that define suitable storage reservoirs, coal beds, or deep aquifers for long-term CO₂ storage.

Federal

Canadian Environmental Assessment Act

The Canadian Environmental Assessment Act (CEAA) would be in effect where there are concerns of transboundary environmental effects between provinces (Section 46) or where a project is initiated on federal lands or by a federal authority. In cases where there is cause for concern about international environmental effects from a project this act would also apply (Section 47). Since CO₂ capture and storage projects would be initiated with the intent of reducing Canada's greenhouse gas emissions as part of the Climate Change Plan for Canada, they would definitely qualify under concern for "international environmental effects."

The environmental assessment process consists of three major steps: (1) a screening or comprehensive study; (2) a mediation assessment by a review panel; and (3) the design and implementation of a follow-up program (CEEA, Section 14). The first two steps are undertaken to consider the following factors: the environmental effects and their significance, public input; technically and economically feasible measures that might mitigate any negative environmental effects that may result from the project (CEEA, Section 16). Additionally they will also consider the purpose of the project, alternative means of carrying out the project, the need for a follow-up program, and the capacity of renewable resources that are likely to be significantly affected (CEAA, Section 16).

Environmental assessments are carried out with the purpose of identifying any harmful environmental effects and should be "conducted as early as is practicable in the planning stages of the project and before irrevocable decisions are made" (CEEA, Section 11). All proposed undertakings for the project including construction, operation, modification, decommissioning, and abandonment should be considered in the environmental assessment process (Section 15).

Under federal jurisdiction some projects may not require the formal assessment. These projects are included under an exclusion list (CEEA, Section 7). The Exclusion List Regulations deal with projects and developments that do not require an environmental assessment while the Inclusion List Regulations deal with projects and developments that *may* require an assessment. It is the opinion of the author that in the case of subsurface storage of CO₂ and projects of similar magnitude that no exclusions would be granted. It should be noted, however, that under the Exclusion List Regulations some additions to or installations at any onshore oil and gas pipeline do not require an environmental assessment, while "physical activities relating to the abandonment of the operation of a pipeline" (Section 15 of the Inclusion List Regulations) may require an assessment.

IN ORDER TO DEVELOP A CANADA-WIDE CO₂ RESERVOIR STORAGE MANAGEMENT SYSTEM IT IS PROBABLE THAT STORAGE RESERVOIRS WITH VERTICAL LIMITS EXTENDING WITHIN THE PROVINCIAL BORDERS WOULD BE UNDER SEPARATE PROVINCIAL JURISDICTIONS. IN CASES WHERE THE

STORAGE RESERVOIRS MIGHT CROSS PROVINCIAL BOUNDARIES, THE US-CANADA BORDER, OR MAY BE SITUATED ON THE CONTINENTAL SHELF, THE GOVERNING AUTHORITY WOULD MOST LIKELY BE FEDERAL. ALTERNATIVELY, PROVINCIAL STORAGE DEVELOPMENT PROJECTS MAY ALL FALL UNDER THE FEDERAL JURISDICTION IF THIS BECOMES AN ISSUE FOR KYOTO PROTOCOL COMPLIANCE IN ORDER TO MEET THE AGREED UPON TARGET REDUCTIONS.



Canadian Environmental Protection Act, 1999

The Preamble to the Canadian Environmental Protection Act (CEPA) states that the Government of Canada “seeks to achieve sustainable development”, “will continue to demonstrate national leadership in establishing environmental standards”, and “is committed to implementing the precautionary principle.” Contained within the CEPA is the consideration of both the short- and long-term human and ecological benefits stemming from any environmental protection measure (Section 2). One would assume that the short- and long-term human and ecological costs and/or risks should also be weighed, especially when considering a subsurface CO₂ storage project.

If the Government of Canada had any jurisdiction over any CO₂ storage projects, the federal environment minister could “release guidelines recommending limits, including limits expressed as concentrations or quantities, for the release of substances into the environment” (CEPA, Section 54(1) (c)). The federal Minister may also issue codes of practice “specifying procedures, practices or release limits” during any phase of project “development and operation, including the location, design, construction, start-up, closure, dismantling and clean-up phases and any subsequent monitoring activities” (CEPA, Section 54 (1) (d)).

Division 6 of the CEPA deals specifically with international air pollution. The Minister shall act if there is “reason to believe that a substance released from a source in Canada into the air creates, or may reasonably be anticipated to contribute to (a) air pollution in a country other than Canada; or (b) air pollution that violates, or is likely to violate, an international agreement binding on Canada in relation to the prevention, control or correction of pollution (Section 166 (1)).” The Governor in Council may make regulations respecting how much of a substance can be released and the monitoring and measurement of the quantity and quality of substance being released (Section 167).

Under Economic Instruments, Sections 322 to 327, there is reference made to “tradeable units.” “The Minister may establish guidelines, programs and other measures for the development and use of economic instruments and market-based approaches to further the purposes of this (CEPA) Act” (Section 322). The Minister may make regulations related to tradeable units that may be relevant for subsurface storage projects if these projects are considered a means of obtaining tradeable units for the individual operators or for the Canadian government.

International

Any project started up in Western Canada would most likely fall under a provincial jurisdiction or under federal jurisdiction if there is any inter-provincial cooperation or if the boundaries of the underground storage reservoirs pass under one or more provincial or territorial boundaries.

Should a case arise where a storage project is undertaken where the subsurface boundaries pass the Canada – US border then it would be a joint venture between the two countries and they would have to decide on a mutually acceptable environmental assessment review process. In such a case the North American Agreement on Environmental Cooperation between Canada, the United States, and Mexico may have application.

Canada ratified the Convention on Environmental Impact Assessment in a Transboundary Context (Espoo Convention) in 1998, however, “in Canada, this treaty applies only to proposed activities under federal jurisdiction exercised in respect of environmental assessment (http://pubx.dfaitmaeci.gc.ca/A_Branch/AES/Env_commitments.nsf/0/2ac8b58bb5e3127685256b6c004aeb69?OpenDocument) .” This means a CO₂ capture and storage project would first need to be deemed to fall under federal jurisdiction before this treaty had any application.

Projects of the nature discussed in this paper would be one way of meeting Canada’s commitment to reduce its greenhouse gas emissions to 6% below 1990 levels by 2008-2012 (Climate Change Plan for Canada 2002, p.7) as part of the Kyoto

Protocol. Canada announced the ratification of the Kyoto Protocol on December 17th, 2002 (http://webapps.dfaitmaeci.gc.ca/minpub/Publication.asp?FileSpec=/Min_Pub_Docs/105789.htm&Language=E).



Table 1 Acts, Regulations and Agreements Related to:

Jurisdiction	Environmental Assessment And Protection
PROVINCIAL	
<i>British Columbia</i>	Environment Management Act Environmental Impact Assessment Regulation
Alberta	Environmental Assessment Act Reviewable Projects Regulations
Saskatchewan	Environmental Protection and Enhancement Act Environmental Assessment (Mandatory and Exempted Activities) Regulation
Manitoba	The Environmental Assessment Act The Environmental Management and Protection Act, 2002 The Environment Act
FEDERAL	
Government of Canada	Canadian Environmental Assessment Act (CEAA) Inclusion List Regulations Exclusion List Regulations Canadian Environmental Protection Act, 1999 (CEPA, 1999)
INTERNATIONAL	Agreements
United Nations (UNFCCC) North American Commission for Environmental Cooperation (CEC) United Nations UNECE	Kyoto Protocol to the United Nations Framework Convention on Climate Change North American Agreement on Environmental Cooperation Convention on Environmental Impact Assessment in a Transboundary Context (Espoo Convention)

Injection Wells and Pipelines

For an effective management system to be in place there will have to be specific regulations related to injection wells and pipelines for CO₂ or there will have to be changes made to include these types of arrangements in the existing regulations. Currently there are no provisions in place to deal specifically with carbon dioxide transport, injection and storage, however a number of provincial regulations exist for the oil and gas industry for the transport and subsurface storage of petroleum and natural gas.

Provincial

British Columbia

The BC Oil and Gas Commission regulates the oil and gas sector in that province (<http://www.ogc.gov.bc.ca/>). Both the Petroleum and Natural Gas Act and the Pipeline Act of British Columbia were looked at in order to determine if there were any relevant sections that could be applied to subsurface CO₂ storage projects. Details on abandonment can be found under a separate heading in this paper. The commission can make regulations establishing standards and equipment to be used for drilling, development, production or storage of petroleum or natural gas or for injecting substances associated with the production or storage of petroleum and natural gas (PNGA, Section 96(1) (g)). This could be expanded to include carbon dioxide if the storage project operated in conjunction with enhanced oil recovery operations. They may also make regulations requiring the “provision of adequate well casing and the proper anchorage and cementation (PNGA, Section 96(1) (k)).”



Similar to the Oil and Gas Conservation Act of Alberta, in order to prevent waste the commission may require that natural gas “be marketed or injected into an underground reservoir for storage or for any other purpose (PNGA, Section 99).” This could be expanded to include CO₂ gas or it may serve as a template for including a similar section in legislation written specifically for geological CO₂ storage.

Assuming the transport of CO₂ would occur through a pipeline system, the Pipeline Regulation under the Pipeline Act of British Columbia may need to be consulted as to the standards used for the “design, fabrication, installation, testing, operation, maintenance, repair or deactivation” of any pipelines involved (Section 12, Pipeline Regulation). According to the Pipeline Regulation of British Columbia, CSA Standard Z276 for Liquefied Natural Gas Production is the standard to follow for natural gas pipeline systems. Alternatively, a new standard may have to be drawn up specifically for the transport of CO₂ gas through its own unique pipeline system depending on the design requirements.

Alberta

In Alberta a person has the right to use a well or drill a well for the injection of any substance into an underground formation, if the person has the approval of the Energy Resources Conservation Board (Mines and Minerals Act, Section 56).

The Alberta Energy Utilities Board is “an independent, quasi-judicial agency of the Government of Alberta (<http://www.eub.gov.ab.ca/bbs/default.htm>)” that regulates the oil and natural gas sector as well as the pipelines in the province. The Board has many guides on its website with some of them listed below. These may be useful for consultation if and when it becomes necessary to develop CO₂ storage guides.

AEUB Guides:

Guide 8 Surface Casing Depth Minimum Requirements

Guide 9 Casing Cementing Minimum Requirements

Guide 20 Well Abandonment Guide

Guide 51 Injection and Disposal Wells - Well Classifications, Completions, Logging, and Testing Requirements

Guide 65 Resources Applications for Conventional Oil and Gas Reservoirs

The Oil and Gas Conservation Act applies to “every well and facility situated in Alberta whenever drilled or constructed, and to any substance obtained or obtainable from such a well or facility (Section 3).” A license must be issued before any associated injecting operations or drilling begins (OGCA-AB, Section 11). The wells must be abandoned and operations suspended when directed by the Board or as required by regulations (Section 27).

The Oil and Gas Conservation Regulations read as follows, “The licensee of a well or the operator of a facility shall post one of the following categories of warning symbol: (a) Category I: Flammable (gas or liquid); Class 3; (b) Category II: Poison Gas; Class 2 (Section 6.020).” Since CO₂ gas is not flammable it is unlikely that the Category I sign would be posted. Under the existing options the Category II sign would most likely apply, since CO₂ gas is poisonous and lethal in high enough concentrations. In addition, a well that could “produce gas containing .01 moles per kilomole of hydrogen sulphide or greater” would also be classified as Category II (Section 6.020). In the case of CO₂ gas a new category may need to be instituted in order to warn of the unique dangers this gas could cause should any leakage occur in the vicinity of an injection well. There may also need to be fenced-in areas directly above the extents of the underground storage reservoirs with appropriate signage to warn against any large-scale soil fluxes.

It is considered “wasteful” if there is any “escape or flaring of gas, if it is estimated that, in the public interest and under sound engineering principles and the light of economics and the risk factor involved, the gas could be gathered, processed if necessary, and it or the products from it marketed, stored for future marketing, or beneficially injected into an underground reservoir (OGCA-AB, Section 1).” This statement lends it support to the injection of CO₂ into a subsurface reservoir as a means of eliminating or reducing the wasteful emissions to the atmosphere of this greenhouse gas. The Board, with the approval of the Lieutenant Governor in Council may actually make regulations requiring that waste gas be injected into an underground reservoir for storage (OGCA, Section 38).

It is interesting to note that there are provisions in the Oil and Gas Conservation Regulations for the injection of “any fluid other than potable water.” Section 6.120 reads that “before any fluid other than potable water is injected to a subsurface



formation through a well" certain things must be in place. Section 6.120 would become important if CO₂ were ever injected in fluid form. Of course CO₂ would most likely fall under the category of a gas and therefore be covered under Section 14.200. Section 14.200 of the regulations states that "where gas, air, water or other substance is injected through a well to an underground formation, it shall be continuously measured by a method satisfactory to the Board."

As will be discussed under the heading of Transportation, it is not known if the CO₂ gas will be transported to the injection well sites by a pipeline but that is the most likely scenario. If the gas were transported in such a manner the Pipeline Act of Alberta would apply.

Saskatchewan

The Lieutenant Governor in Council may make regulations authorizing or requiring the drilling, casing, cementing, operating and plugging of wells to prevent the escape of oil or gas from one stratum to another and the pollution of fresh water supplies (OCGA-SK, Section 18). There is no definition of gas in the Oil and Gas Conservation Act so there is no way of assessing whether or not carbon dioxide would be included as a gas for any subsurface storage projects. According to the Pipelines Act, 1998, the Lieutenant Governor in Council may make regulations: (g) prescribing specifications and standards for the construction, alteration, operation and abandonment of pipelines; and (m) the methods and equipment to be used for the measurement of any substance transmitted in any pipeline (Section 25).

Saskatchewan Industry and Resources (<http://www.ir.gov.sk.ca/>) has several guidelines on its website under the Saskatchewan Oil and Gas Resources section and a couple are listed below that may have relevance in drawing up guidelines and application forms for the subsurface storage of CO₂ gas and the associated activities. There are many other guidelines on the website that could also have some relevance in formulating appropriate guidelines for a CO₂ capture and storage regulatory system in that province.

Saskatchewan Guidelines: PNG Guideline 20 – Application for a Gas Storage Project
PNG Guideline 12 – Application for an Enhanced Recovery
Scheme other than a Waterflood

Manitoba

The Public Utilities Board of Manitoba supervises "the construction and operation of natural gas and propane pipelines, and make sure that gas and propane are safely distributed to Manitoba consumers (<http://www.gov.mb.ca/finance/cca/publutil/index.html>)."

In Manitoba The Oil and Gas Act applies to the exploration for oil and gas, the drilling of wells and their abandonment as well as the operation and abandonment of storage reservoirs (Section 3(1)). Abandonment and storage reservoirs are covered under their respective headings in this paper. The Gas Pipe Line Act would apply if CO₂ was transported via a pipeline system from source to injection well.

Federal

The Canada Oil & Gas Operations Act does not apply to the provinces in mention because it states the following in its application: "This Act applies in respect of the exploration and drilling for and the production, conservation, processing and transportation of oil and gas in (a) the Northwest Territories, Nunavut and Sable Island, and (b) submarine areas, not within a province, in the internal waters of Canada, the territorial sea of Canada or the continental shelf of Canada, other than of oil and gas in the adjoining area, as defined in section 2 of the Yukon Act (Section 3)."



Table 2 Acts, Regulations and Agreements Related to:

Jurisdiction	Injection Wells and Pipelines
PROVINCIAL	
<i>British Columbia</i>	Pipeline Act Pipeline Regulation Petroleum and Natural Gas Act
Alberta	Pipeline Act Mines and Minerals Act Oil and Gas Conservation Act
Saskatchewan	The Pipelines Act, 1998 The Oil and Gas Conservation Act
Manitoba	The Gas Pipe Line Act The Oil and Gas Act
FEDERAL	
Government of Canada	**Canada Oil and Gas Operations Act has no jurisdiction in the provinces of BC, AB, SK, and MB National Energy Board Act
INTERNATIONAL	
	None identified as applicable

Transportation

The manner in which the CO₂ gas would be transported from its source location to a subsurface storage site is not certain. For the Weyburn project a pipeline is used to deliver gas from North Dakota (<http://www.ptrc.ca/projects/veyburn.htm>). The most likely method of transport will be via a pipeline system, although truck or train could also deliver it to a site where it could possibly be stored aboveground before being injected by means of injection wells. For transportation via a pipeline system the governing acts would be the various provincial pipeline acts.

Each of the four Western provinces and the federal government have their own acts dealing with the transportation of dangerous goods, however it is highly unlikely that CO₂ would ever be classified as a dangerous or hazardous good for transport in its gaseous phase. Carbon dioxide (CO₂) gas is colourless, odourless and non-flammable (Material Safety Data Sheets). One concern with injecting CO₂ into a subsurface environment, however, is the possibility for it to come in contact with water if it migrates through any aquifers. In the presence of water CO₂ forms carbonic acid which is corrosive. The corrosive fluid may reduce the time that an injection well remains plugged if it eats away at the material put in place.

“The National Energy Board Act takes jurisdiction for transportation of CO₂ across provincial or international boundaries and onshore pipelines are covered under the Onshore Pipeline Regulations, which set out the technical and safety requirements for all aspects of a pipeline’s life cycle (Keith and Wilson, p.26).”



Table 3 Acts, Regulations and Agreements Related to:

Jurisdiction	Transportation
PROVINCIAL	
<i>British Columbia</i>	Pipeline Act Pipeline Regulation Transport of Dangerous Goods Act
Alberta	Dangerous Goods Transportation and Handling Act Pipeline Act
Saskatchewan	The Dangerous Goods Transportation Act The Pipelines Act, 1998
Manitoba	The Dangerous Goods Handling and Transportation Act The Gas Pipe Line Act
FEDERAL	
Government of Canada	Transportation of Dangerous Goods Act National Energy Board Act
INTERNATIONAL	
	None identified as applicable

Storage

Storage is the key principle for a subsurface CO₂ storage management system. The existing regulations, surrounding reservoir storage, were drawn up for petroleum and natural gas and have no provisions in place for the storage of CO₂ gas. The natural gas regulations never intended for the type of long term storage required for CO₂ so at most they would serve as a reference for the kinds of considerations that should be included if new legislation was implemented.

Considering the intention for storing CO₂ at depth to serve as a method of reducing Canada’s greenhouse gas emissions, it is unlikely that the natural gas regulations would be expanded to include CO₂ because natural gas is stored for a different reason entirely. Natural gas is sometimes stored in subsurface reservoirs to meet demand during peak times, such as winter, when energy consumption increases. For example, in Saskatchewan “TransGas typically injects gas for customers during the off-peak season in summer to fill its storage facilities located throughout the province. Customers withdraw gas from storage over the winter, particularly during extended cold snaps when the pipeline system is nearing capacity.”
<http://www.saskenergy.com/news/newsreleases/030828.htm>

British Columbia

Part 14 of the Petroleum and Natural Gas Act deals with the subject of underground storage for petroleum or natural gas. “A person must not explore for a storage reservoir unless (a) the person is licensed by the division head, or (b) exploration consists only of geophysical exploration (Section 126(1)).” The storage reservoir exploration activities must be at least 3 km away from any mine (Section 126 (4)). “The Lieutenant Governor in Council may by regulation designate land as a storage area (Section 127)” and “ninety days after designation of land as a storage area, a right, title and interest in a storage reservoir in or under the storage area and in any water inside the storage reservoir is vested in the government free of encumbrances (Section 128(1)).” A holder of a petroleum or natural gas permit, drilling license or lease or an exploration licence may apply for a lease (Section 130) but must not develop or use a storage reservoir until a storage licence has been granted by the commission (Section 131). The Petroleum and Natural Gas Storage Reservoir Regulation applies to the granting of leases for a storage reservoir for natural gas. It does not make any mention to the reservoir storage of carbon dioxide gas.

Alberta

Interestingly, the Mines and Minerals Act of Alberta makes reference to storage rights (Section 1) as the right to inject fluid mineral substances into a subsurface reservoir for the purpose of storage. “Where a person owns the title to a mineral in any



land and operations for the recovery of the mineral result or have resulted in the creation of a subsurface cavern in that land, that person is the owner of the storage rights with respect to that subsurface cavern to the extent that it lies within that land (Section 57).” This act applies to the mines and minerals belonging to the Crown and where the context so permits to all wells in Alberta (Section 2) so it may or may not be applicable to injection wells in the context of subsurface CO₂ storage. It also reads that the Minister may enter into agreements with persons, other provinces, or the Government of Canada respecting the storage of substances in subsurface reservoirs (Section 9). This section leads one to believe that CO₂ could be included as a substance considered for subsurface storage but it is not clear in the act. Sections 58 and 59 outline the right to work through other minerals for the objective of exercising subsurface storage rights.

The CO₂ Projects Royalty Credit Regulation, which is associated with the Mines and Mineral Act, contains the only definition for CO₂ found anywhere during this entire statutory and regulatory review. Under Section 1 of the regulation, “CO₂” is defined as “a gaseous mixture consisting mainly of carbon dioxide.” Furthermore a “CO₂ project” is defined as “a scheme approved under the Oil and Gas Conservation Act (i) for enhanced recovery of petroleum and natural gas from any underground formation through the injection of CO₂ into the formation, or (ii).... to recover natural gas from a coal seam.” This means that the only acceptable storage of CO₂ presently addressed in the laws of Alberta is that associated with enhanced oil or gas recovery. This has very important implications because it clearly does not contain provisions for storage alone. A more stringent definition of CO₂ would be required should the province of Alberta decide to draw up acts and regulations for the capture and storage of this gas, as the present definition is too general. If the intent of the injections into subsurface formations is to be counted as a reduction in greenhouse gas emissions, a definition of CO₂ should give a percentage volume that must be pure CO₂ while allowing for any impurities. This definition would be limited by the capabilities of the extraction technologies in existence, especially if the source of gas is the waste stream from a coal plant for example.

Saskatchewan

Section 17.1(1) of The Oil and Gas Conservation Act states that “Notwithstanding anything in this Act or the regulations, the minister may make orders approving plans for: (b) disposing of oil-and-gas wastes or non-oil-and-gas wastes in subsurface formations.” Under Section 55 of the same act it reads, “ No gas shall be used, consumed or otherwise disposed of in the province until a permit authorizing the use, consumption or disposition is granted by the minister.”

The Oil and Gas Conservation Regulations 1985 stipulates that “a plan for the disposal of oil-and-gas wastes or non-oil-and-gas wastes into subsurface formations must be accompanied by (a) the written consent of all owners and all fee simple mineral owners, other than the Crown, that in the opinion of the minister may reasonably be adversely affected by the disposal; and (c) any other information or material that the minister may require (Section 76(1)).” It continues to read that “no operator shall allow oil-and-gas wastes or non-oil-and-gas wastes to constitute a hazard to public health or safety or to contaminate fresh water or arable land (Section 76(3)).”

A plan for enhanced recovery of oil or gas that includes “the injection of oil, gas or other fluids” must also “ be submitted to the department for approval by the minister (Section 77(1), Oil and Gas Conservation Regulations 1985).”

Manitoba

One of the purposes of the Oil and Gas Act is to provide for the safe and efficient development and operation of storage reservoirs (Section 2(1)). Included in the definition of “waste”, from the Oil and Gas Act in Manitoba, is “the inefficient or improper storage of oil and gas, whether on the surface or underground and the escape or flaring of gas, where in the opinion of the minister, having regard to sound engineering and economic principles, the gas could be gathered, processed if necessary, marketed or beneficially injected into a reservoir (Section 1).”

A storage permit is needed to develop and operate a storage reservoir in Manitoba and the development and operation of a storage reservoir is subject to *The Public Utilities Board Act* (OGA, Sections 160&161). Any applications for a storage permit must include any prescribed performance security (OGA, Section 162).

Monitoring and Measurement

Nowhere, in the existing legislation, is any reference made to monitoring or measuring carbon dioxide gas. In order to determine the quantity and quality of gas being injected there would have to be some standards in place governing the methods and equipment to be used. This is huge in terms of meeting reductions for the Kyoto Protocol because unless there



Table 4 Acts, Regulations and Agreements Related to:

Jurisdiction	Storage
PROVINCIAL	
<i>British Columbia</i>	Petroleum and Natural Gas Act Petroleum and Natural Gas Storage Reservoir Regulation
Alberta	Mines and Minerals Act The CO ₂ Projects Royalty Credit Regulation
Saskatchewan	The Oil and Gas Conservation Act The Oil and Gas Conservation Regulations, 1985
Manitoba	The Oil and Gas Act The Public Utilities Board Act
FEDERAL	
Government of Canada	**Canada Oil and Gas Operations Act has no jurisdiction in the provinces of BC, AB, SK, and MB(Section 3. Application) National Energy Board Act
INTERNATIONAL	
	None identified as applicable

is a standardized way of verifying the percentage of gas being injected that is actually CO₂ there cannot be any accurate accounting system. An accurate accounting system is paramount if carbon credits are to be assigned. Although no reference is made to the monitoring *or measurement of CO₂ gas, we do find mention of reporting and measurement requirements for oil and gas in some of the regulations.*

British Columbia

Division 2 of the Drilling and Production Regulation deals with the “Metering and measurement of gas”; Division 4 deals with “Pressure and Injection Measurement”; and Section 97 handles the “Measurement of fluids injected.” Section 97 stipulates that “When water, gas, air or any other fluid is injected through a well to an underground formation, it must be continuously measured by a method acceptable to an authorized commission employee.”

Alberta

In Alberta, “ The Board may make regulations (aa) prescribing (i) methods and facilities to be utilized for the measurement of any substance transmitted by a pipeline, (ii) methods of recording the measurement, and (iii) standard conditions to which the measurements are to be converted (Section 3(1), Pipeline Act).”

“The surface and subsurface equipment of a completed oil or gas well shall be of such nature and so arranged as to permit the ready measurement of the tubing pressure, production casing pressure, surface casing pressure and bottom hole pressure, and to permit any reasonable test required by the Board except insofar as a completion technique approved by the Board precludes such measurement or test. (Section 6.130(1), Oil and Gas Conservation Regulations).” Part 14 of this regulation deals specifically with the details of measurement in the oil and gas sector.

Saskatchewan

Section 96(1) of the Oil and Gas Conservation Regulations 1985 of Saskatchewan addresses well and plant records. In this section it states that “every person who produces, sells, purchases, acquires, stores, transports, refines or processes oil or gas shall keep and maintain complete and accurate records.” Where “gas is injected or disposed of into a well, the owner shall keep a daily record showing (a) the gas injected or disposed of into the well; (b) the source from which the gas was obtained; (c) the particulars of any treatment to which the gas has been subjected; and (d) the pressure used in the injection of the fluid (Section 96(5)).”



“For the purposes of leak detection and material balance, every operator of a pipeline for which a license has been issued shall ensure that all substances transported by that pipeline are measured accurately (Section 15(1), Pipelines Act 2000).” This would be especially important for detecting leaks of CO₂ to the atmosphere because there may be penalties involved for leakage. Oil or gas well operators, pipeline operators, and operators of “any storage receptacle in which gas is received or stored” are expected to “notify the department, by the most expeditious method, of any leak or malfunction of equipment (Section 106(1), Oil and Gas Conservation Regulations 1985).”

Manitoba

Manitoba’s Drilling and Production Regulation, which falls under The Oil and Gas Act, has a few sections dealing with measurement and reporting. Section 106 covers the measurement of gas, Section 108 deals with the measurement of injection fluids, and Section 120 states that the “licensee of a well that is used for injection or disposal of water or any other substance” should file a report once a month detailing the operations at that injection well.

Table 5 Acts, Regulations and Agreements Related to:

Jurisdiction	Monitoring and Measurement
PROVINCIAL	
<i>British Columbia</i>	Drilling and Production Regulation
Alberta	Oil and Gas Conservation Regulations Pipeline Act
Saskatchewan	Oil and Gas Conservation Regulations, 1985 Pipelines Regulations, 2000
Manitoba	Drilling and Production Regulation
FEDERAL	
Government of Canada	None identified as applicable
INTERNATIONAL	
	None identified as applicable

Mitigation of Risk: Human and Environmental Health

Both the environmental assessment and protection acts as well as the occupational health and safety acts of the provinces and the federal government serve to achieve the goal of protecting human and environmental health. According to the Canadian Environmental Assessment Act, “mitigation means, in respect of a project, the elimination, reduction or control of the adverse environmental effects of the project, and includes restitution for any damage to the environment caused by such effects through replacement, restoration, compensation or any other means (Section 2).” The purpose of the various occupational health and safety acts is to protect the right to a safe and healthy work environment and to protect workers from the hazards and risks that may be encountered while on the job.

Mitigation of risks to human and environmental health would take place prior to, during and following the operation of a subsurface CO₂ storage project. In order to eliminate or reduce effects on the environment and on people residing or working within the vicinity of an injection well or above a storage reservoir, various safeguards would need to be put in place. These might include operational plans with emergency procedures in place, having backup monitoring systems for detecting leaks, and providing employees with safety training and the proper equipment to work in areas where there are or may be elevated CO₂ levels.



At certain levels carbon dioxide *can* cause harm. Some of the symptoms of exposure to elevated levels of CO₂ gas include dizziness, headache, elevated blood pressure and tachycardia, a condition that involves an abnormally rapid heartbeat (Material Safety Data Sheets). Considering the fact that any exposure that occurs would be outside, there would be a low risk of concentrations reaching levels high enough to cause these symptoms. If, however, an injection well was located in a natural depression the chances of concentrations becoming elevated in the vicinity would increase. If the injection well were housed inside a building the chances would increase even more.

The federal Fisheries Act reads that “no person shall deposit or permit the deposit of a deleterious substance of any type in water frequented by fish or in any place under any conditions where the deleterious substance or any other deleterious substance that results from the deposit of the deleterious substance may enter any such water (Section 36).” Any migration of CO₂ upwards that reached a water body where fish were present in sufficient enough concentrations would be considered deleterious. A deleterious substance is defined as “any substance that, if added to any water, would degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to use by man or fish that frequent that water.”

Protection of vegetation from elevated CO₂ levels, due to the migration from depth or via the injection well, is a more complicated issue. There are two general possibilities to be concerned with. First, and the most likely route of leakage, would be the injection wells themselves. Second is the possibility of the gas migrating to the surface as it finds its way through more permeable bedrock, aquifers, and the soil before finding its way to the surface. If any CO₂ gas migrates to the surface in very low levels over a wide area it would be harder to detect than noticeably elevated levels concentrated around one injection well. How do you distinguish between the effects of gas migrating or leaking to surface and the effects of elevated atmospheric levels? How do you establish a cause and effect relationship when there are so many other factors affecting plant growth like soil moisture, soil type, temperature and various nutrient levels? Is there a way to determine the source of the elevated CO₂ levels? How great is the risk to reducing plant growth and habitat for wildlife if leakage at surface should occur? Finally, what would be the risk to any crops that may be located over the site of a subsurface CO₂ storage reservoir? These are all questions that need answering.

As was already noted, mitigation involves the restoration or reclamation of, or compensation for any site or land that may have been damaged or contaminated as a result of a project. Means of compensation are discussed in the Financial Requirements section 9.0, which discusses some of the financial requirements that are already in place.

Table 6 Acts, Regulations and Agreements Related to:

Jurisdiction	Mitigation of Human Health Risks
PROVINCIAL	
<i>British Columbia</i>	Environmental Management Act Environmental Assessment Act Workers Compensation Act
Alberta	Environmental Protection and Enhancement Act Occupational Health and Safety Act
Saskatchewan	The Environmental Assessment Act The Environmental Management and Protection Act, 2002 The Occupational Health and Safety Act, 1993
Manitoba	The Environment Act The Workplace Safety and Health Act
FEDERAL	
Government of Canada	Canadian Environmental Assessment Act Canadian Environmental Protection Act, 1999 Fisheries Act Canada Labour Code
INTERNATIONAL	



Abandonment

Abandonment occurs once a well and the associated facilities are shut down and no longer in use. It involves plugging and capping the well and the eventual turnover of ownership to the government. In the case of CO₂ storage, it would have to be decided if abandonment would relinquish the well operator from any liability for damage due to leakage. There may be a period of time established, during which the operator is liable for any damages at the end of which abandonment funds would be used to address any problems that may arise.

British Columbia

The commission can make regulations and they may require an operator to submit applications and obtain their approval before a well can be abandoned (PNGA, Section 96(1) (d)). In fact, "a person is deemed not to have abandoned a well, test hole or production facility until the commission issues, on application, a certificate of restoration respecting the well, test hole or production facility (PNGA, Section 84)."

No wells or test holes can be left "unplugged or uncased" after they are no longer in use (Section 44, Drilling and Production Regulation) and "all permeable formations must be isolated with cement (Section 45)." The Drilling and Production Regulation provides further detail on the plugging requirement for wells in Section 45 and plugging requirements for test holes in Section 46. Section 48 discusses the surface restoration requirements for the area surrounding a well. Finally, before a well is abandoned "the minimum requirement of (a) a gamma ray log must be taken from ground level of the well to total depth, and (b) a resistivity and porosity log must be taken from the base of the surface casing of the well to the total depth of the well, with all pertinent data recorded (Section 53)."

Alberta

According to Section 3.010 of the Oil and Gas Conservation Regulations of Alberta, "abandonment operations, including well abandonment, casing removal, zone abandonments and plug backs, shall be conducted in accordance with the current edition of Guide G-20 'Well Abandonment', published by the Board."

The Oil and Gas Conservation Act states that, "Abandonment of a well or facility does not relieve the licensee, approval holder or working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility for the costs (Section 29)." As this section was not necessarily written with the idea that the wells in mention would be used to inject CO₂ gas into subsurface formations, this may or not be the case for injection wells.

Once the injection wells at a given locate were abandoned it is safe to assume that the abandonment of the pipelines that supplied the injection wells would follow. For the abandonment of a pipeline in Alberta, the operator must ensure that it is "(a) physically isolated or disconnected from any operating facility, (b) cleaned, if necessary, (c) purged with fresh water, air or inert gas, (d) left in a safe condition, and (e) plugged or capped at all open ends (Section 67, Oil and Gas Conservation Regulations)."

Saskatchewan

Although there are no mentions in The Pipelines Act, 1998 or The Oil and Gas Conservation Act of Saskatchewan regarding the abandonment of injection wells there is a small section in another provincial act that may have some relevance. The Oil and Gas Conservation Regulations 1985 also provide some details on well abandonment in general. Sections 53 and 55 of The Surface Rights Acquisition and Compensation Act deals with abandonment and surrender of rights related to the use of land.

In the Oil and Gas Conservation Regulations 1985 of Saskatchewan it states that "no well, structure test hole or oil shale core hole is to be permitted to remain unplugged or uncased after it is no longer used for the purpose for which it was drilled or converted (Section 35(1))." Before a well can be abandoned "the operator shall have the following logs taken unless otherwise approved: (a) an approved resistivity log or standard electric log; (b) an approved radioactivity log, including both natural and induced radioactivity or an approved porosity curve (Section 86(1))."

The Saskatchewan Pipelines Regulations 2000 (Section 9) addresses the abandonment of pipelines defined as "the permanent deactivation of a pipeline or part of a pipeline, whether or not it is removed (Section 2)."



Manitoba

Once they are given approval to abandon a well, operators must abandon wells, in accordance with regulations and any terms or conditions that may be stipulated (OGA, Section 122). “Notwithstanding the issuance of a Certificate of Abandonment under this section, the holder of a licence or permit in respect of an abandoned well or oil and gas facility is liable for the costs of any repair or rehabilitation required, within six years from the day of issuance of the Certificate of Abandonment (Section 171(4)).”

The Drilling and Production Regulation has more detailed descriptions of the activities to be conducted as part of well abandonment and even includes a listing of how much notice must be given before commencing abandonment (Part 6).

Table 7 Acts, Regulations and Agreements Related to:

Jurisdiction	Abandonment
PROVINCIAL	
<i>British Columbia</i>	Petroleum and Natural Gas Act Drilling and Production Regulation
Alberta	Oil and Gas Conservation Act Oil and Gas Conservation Regulations
Saskatchewan	The Surface Rights Acquisition and Compensation Act Oil and Gas Conservation Regulations, 1985 Pipelines Regulations, 2000
Manitoba	The Oil and Gas Act Drilling and Production Regulation
FEDERAL	
Government of Canada	None identified as applicable
INTERNATIONAL	
	None identified as applicable

Long term Ownership

Although the current legislation takes into consideration the short-term ownership of the minerals, oil, and gas for the provinces there are no provisions for long term ownership on the scale necessary for the geologic storage of CO₂.

Any system put into place today has to examine the future consequences. Although it will most likely be individual companies who initially drill and inject gas into subsurface reservoirs, ultimately the responsibility associated with those abandoned wells will fall upon the shoulders of our governments and those that elect them. The public will need to resume ownership of these wells once the companies that constructed them cease to exist. It is expected that it could take on the order of tens of thousands of years before the risk associated with leakage or migration to the surface is substantially low enough to no longer be a concern to human and environmental health (Keith and Wilson, p. 10).

Along with the issue of long term ownership is liability. An effective statutory and regulatory framework must address liability to be complete. There should be set in place a framework that recognizes who is responsible for accidental or unintentional discharges and or CO₂ gas leaks. Furthermore, regulations should stipulate that measures are put in place to safeguard against such incidences or to develop acceptable concentration levels at surface.

Financial Requirements - Funds/Securities



Many of the laws in place governing oil and gas operations and mining operations in Western Canada have provisions put in place which require companies/operators to provide proof of financial responsibility should anything go awry. In addition there are some funds already in place to deal with any emergencies, leakage, discharges etc. that may occur once a well or mine has been abandoned and is vested in the Crown. These funds fall under two general categories: (1) Emergency Funds; and (2) Abandonment Funds. Emergency funds are drawn upon during the operation of a mine or well site in the event that some damage or danger of damage to the environment is imminent. Abandonment funds are set up by the provincial governments and companies must pay into them as part of their operations so that there is a certain cushion to deal with any incidents that may take place once the site is no longer in active use.

Provincial

British Columbia

The Mines Act, which “applies to all mines during exploration, development, construction, production, closure, reclamation and abandonment (Section 2)” outlines financial requirements that would need to be fulfilled if any storage projects made use of space left from an abandoned mine. First of all, a permit must be obtained from an inspector before any mine-related work can begin. As part of obtaining the permit, the chief inspector may require that the owner, agent or manager “deposit a security in an amount and form satisfactory to the chief inspector so that, together with the deposit under subsection (4) and calculated over the estimated life of the mine, there will be money necessary to perform and properly carry out” any mine reclamation and to protect any land or watercourses that may be affected (Section 10). Secondly, under the Mines Act there is a Mine Reclamation Fund (Section 12). This fund is where the security, as described in Section 10, is deposited.

The Petroleum and Natural Gas Act of BC has financial requirements specifically for storage reservoirs, but not in the context of CO₂. Any person who enters land to “develop or use a storage reservoir is liable to pay compensation to the land owner for loss or damage caused by the entry, occupation or use (Section 9(a)).” They may also have to pay rent if the board orders them to do so (Section 9(b)).

Alberta

Environmental Protection Security Fund (used to be the Surface Reclamation Fund)

“The Environmental Protection Security Fund shall be held and administered by the Provincial Treasurer in accordance with this Act, and the Provincial Treasurer shall maintain a separate accounting record of the Fund (EPEA, Section 32).”

The Orphan Fund set up under the Oil and Gas Conservation Act is also known as the abandonment fund (Section 69). One purpose of this fund is to pay for suspension costs, abandonment costs and related reclamation costs in respect of orphan wells and facilities (Section 70).

Division 2 of the Conservation and Reclamation Regulation deals with securities for conservation and reclamation of given land with the objective of returning “the specified land to an equivalent land capability (Section 2).” These securities must be in place before approval is granted for the construction of certain facilities. It should be noted that “an operator that applies for an approval for the construction of a pipeline” is not required to provide security (Section 17.1). This may or may not be the case for a pipeline that carries CO₂. If a security *was* required as part of the approval process the Minister could decide to return “all or part of the security provided” once a reclamation certificate is issued (Section 22). The Minister may also decide to “retain all or part of the security” for up to five years in certain cases (Section 23). Finally, “the Minister may order that all or part of the security provided by the operator be forfeited” where the operator fails to comply (Section 24). In such cases the amount of the security would be transferred from the “Environmental Protection Security Fund to the Environmental Protection and Enhancement Fund (Section 24(2)).” “Where the amount of the forfeited security exceeds the amount required for conservation and reclamation, the Minister of Finance shall on the direction of the Minister pay the excess to the operator. Where the amount of the forfeited security is insufficient to pay for the cost of conservation and reclamation, the operator remains liable for the balance (Section 24(5&6)).”

The Oil and Gas Conservation Regulations also have security provisions in place when it comes to wells and their associated facilities. “The Board may require a licensee to provide a security deposit to offset the estimated costs of suspending, abandoning or reclaiming a well, facility, well site or facility site”, as well as to “offset the estimated costs of carrying out any other activities necessary to ensure the protection of the public and the environment (Section 1.100(2)).” This type of security deposit can be returned “together with earned interest, where the Board is satisfied that the licensee has fully met all



of the obligations and carried out all of the activities in respect of which the security deposit was provided (Section 1.100(10)).”

Saskatchewan

THE SASKATCHEWAN EMPA STATES UNDER SECTION 81(XX): “THE LIEUTENANT GOVERNOR IN COUNCIL MAY MAKE REGULATIONS REQUIRING OWNERS, OPERATORS AND PERSONS INSTALLING, SERVICING, TESTING AND DECOMMISSIONING STORAGE TANKS, CONTAINERS OR FACILITIES FOR HAZARDOUS SUBSTANCES TO OBTAIN INSURANCE OR PERFORMANCE BONDS, TO DEPOSIT FUNDS IN ANY FINANCIAL INSTITUTION APPROVED BY THE MINISTER AND IN ANY AMOUNTS THE MINISTER MAY CONSIDER NECESSARY, TO ESTABLISH TRUST FUNDS OR TO PROVIDE PROOF TO THE MINISTER OF FINANCIAL SOUNDNESS TO COVER POSSIBLE CONTAMINATION OR POLLUTION.”

The OCGA-SK refers to an Oil and Gas Environmental Fund. The Lieutenant Governor in Council may make regulations establishing such a fund, designating what should be deposited in this fund, and prescribing the purposes for which withdrawals may be made from the fund (Section 18.4). Section 18.4 of the Oil and Gas Conservation Regulations 1985 also refers to this fund.

Manitoba

Under Section 41(1) of the EA of Manitoba the “Lieutenant Governor in Council may make regulations (i) respecting the requirement of evidence of financial responsibility in the form of an insurance or an indemnity bond, or other form as may be satisfactory to the director, for persons owning or operating developments that will or may cause environmental damage.” Section 45 of the EA, entitled ‘Sale of marketable emission rights’, that the “revenue so generated may be held in trust by the Minister of Finance as an environmental contingency fund, to be used by at the request of the minister in the event of an environmental emergency.”

The Gas Pipe Line Act of Manitoba requires that every owner is insured “against liability that it may incur to others by reason of negligence on its part, or on the part of its servants or agents, in the construction or operation of a gas pipe line or for any other reason; and the insurance shall be to such an amount as is approved by the board (Section 11).”

MANITOBA’S MINES AND MINERALS ACT OUTLINES THE MINE REHABILITATION FUND WHICH WAS ESTABLISHED TO PAY FOR THE COST OF REHABILITATION WORK DURING THE CLOSURE OF A MINE. WHEN, IN THE OPINION OF THE MINISTER, NO MORE MONEY WILL HAVE TO BE WITHDRAWN FROM THE FUND FOR CLOSING A MINE IT MAY BE REFUNDED, ALONG WITH ANY INTEREST EARNED, TO THE PROPONENT (SECTION 195).

In order to obtain a permit or license under The Oil and Gas Act a performance is sometimes required. This performance deposit is used when the licence or permit holder fails to comply with the act in order to defray costs associated with drilling, suspension of operation, abandonment or rehabilitation of a well or well site (Section 168(1)). The Abandonment Fund, also included in The Oil and Gas Act, is a “prescribed non-refundable levy on each licence or permit issued” or it may also be payable annually at the discretion of the director on wells that are inactive or not being used for the purpose they were drilled for (Section 172(1)). The minister may authorize the use of this fund for dealing with any spills, leaks or other events where there is harm done to the environment (Section 172(4)).

**Table 8 Acts, Regulations and Agreements Related to:**

Jurisdiction	Financial Requirements
PROVINCIAL	
<i>British Columbia</i>	Mines Act Petroleum and Natural Gas Act
Alberta	Environmental Protection and Enhancement Act Conservation and Reclamation Regulation Oil and Gas Conservation Act Oil and Gas Conservation Regulation
Saskatchewan	The Environmental Management and Protection Act, 2002 The Oil and Gas Conservation Act Oil and Gas Conservation Regulations, 1985
Manitoba	The Environment Act The Gas Pipe Line Act The Oil and Gas Act
FEDERAL	
Government of Canada	None identified as applicable
INTERNATIONAL	
	None identified as applicable

APPENDIX D

KEY FEDERAL LEGISLATION THAT COULD AFFECT CARBON SEQUESTRATION PROJECTS

Key Federal Legislation That Could Affect Carbon Sequestration Projects (Vine, 2003)

<p>National Environmental Policy Act (NEPA, 1969)</p>	<p>Requires the preparation of an environmental document (such as an Environmental Impact Statement) when a federal government agency is the developer or issues a permit for a project or when federal government funds are used for a project. The primary purpose of the document is to disclose in a public process the environmental impacts of the project. Where significant environmental impacts are identified, the lead agency must discuss the impacts of the project. The federal lead agency must 1) document how these impacts will be mitigated, 2) provide alternatives to the project which minimize or avoid negative impacts to the extent possible, or 3) document why such measures are not implemented.</p>
<p>Clean Water Act (CWA, 1977)</p>	<p>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 (wastewater) from point sources and non-point sources. Uses area control or performance standards, such as requiring Best Management Practices or operational activities found to minimize impacts to water quality. Another example is the Total Maximum Daily Load (TMDL) approach. This is watershed-oriented. Operational activities are restricted to those that may result in the deposition of a pollutant that does not negatively impact water quality. Pollutants include, but are not limited to, chemicals, soil sediment, vegetative debris, manure, or any other substance that would negatively impact the “beneficial uses of water.” The TMDL provisions of Section 303 of the CWA require that levels of pollutants protective of beneficial uses from both point and non-point sources be set for impaired water bodies.</p>

Key Federal Legislation That Could Affect Carbon Sequestration Projects (Vine, 2003)

<p>Clean Air Act (CAA, 1963, 1970, 1990, 199)</p>	<p>Requires control of 1) particulate matter from industry combustion sources, 2) total reduced sulfur compound emissions, and 3) hazardous air pollutant emissions from production sources. New Source Review (NSR) is a permit program that is operated on both the federal and state levels. The federal program draws guidance from the federal CAA. Title V of the 1990 Clean Air Act Amendments created a federal permit program that can be administered by state and local programs. These programs issue permits for new stationary sources of emissions so that emissions will not exceed the national ambient air quality standards (NAAQS) set for the six criteria pollutants. Criteria pollutants are sulfur dioxide (SO₂), particulate matter less than or equal to 10 μm (PM₁₀), nitrogen dioxide (NO₂), carbon monoxide (CO), ozone (O₃), and lead (Pb).</p> <p>Under NSR permits, all major new and modified stationary sources must use Best Available Control Technology (BACT) to control emissions. BACT is defined as “. . . an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator (EPA), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable” (40 CFR 52.21(b)).</p> <p>The state BACT is often equivalent to the federal Lowest Achievable Emission Rate (LAER). An area may be in attainment for one pollutant and in nonattainment for another one. In this</p>
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**Key Federal Legislation That Could Affect Carbon Sequestration Projects
(Vine, 2003)**

	<p>case, the federal BACT requirement only applies to the pollutant and its precursors for which the area is already in attainment. In contrast to BACT (which applies to criteria pollutants), maximum achievable control technology (MACT) is a federal emissions limitation oriented toward hazardous air pollutants and is based on the best demonstrated control technology or practice used on a comparable source that emits at least one of the 188 federal hazardous air pollutants (HAPs) named in section 112 (b) of the federal Clean Air Act.</p> <p>New source performance standards (NSPS) are uniform emission standards that are established by EPA and applied nationally. They limit the amount of pollution that can be emitted from new sources or established sources undergoing modifications. The best available retrofit control technology (BARCT) designation applies only to existing sources and sets air emission limits based on the maximum reduction achievable. The limit is established after examining environmental, economic, energy, and other impacts. BARCT varies from district to district, depending on its air quality designation, sources of pollutants, and contribution to the problem. If one air quality management district adopts a BARCT requirement, it does not mean that other districts will adopt the same requirement.</p> <p>The NSR permit program includes Prevention of Significant Deterioration (PSD) permits that apply to new sources in areas in compliance with the NAAQS. For example, a facility may need a PSD permit for carbon monoxide (CO) and NSR (noncompliance) permit for ozone</p>
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Key Federal Legislation That Could Affect Carbon Sequestration Projects (Vine, 2003)	
	precursors. In this case, the facility must install federal LAER requirements for NO _x and volatile organic compounds (ozone precursors) and federal BACT equipment to control CO. Federal PSD permits, whether issued by delegated air districts or the EPA, are subject to review by the EPA Environmental Appeals Board (EAB).
Safe Drinking Water Act (SDWA, 1974)	Led to EPA's Underground Injection Control (UIC) Program setting requirements for different Class Injection Wells. Class II Wells relate to oil and gas production activities and include CO ₂ injection for enhanced recovery and/or storage related production operations. Under the SDWA, states need only to regulate Class II Wells in an "effective manner." Class II Injection Well regulations may not adequately address needs for assessing long-term storage efficiency (40 CFR 144-148).
Endangered Species Act (ESA, 1973)	Administered by the U.S. Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service (NMFS) to protect endangered and threatened plant and animal species and provide a means to conserve designated "critical habitat" for such species. The ESA prohibits any <i>taking</i> (which includes causing mortality, injury, "harassment," or adverse modification of critical habitat) of a listed species without a permit. Federally regulated activities must generally satisfy regulators such as the USFWS or NMFS that the proposed activity is consistent with <i>recovery</i> of listed populations.
The Migratory Bird Treaty Act (MBTA, 1918) and the Bald Eagle Protection Act (BEPA, 1940)	Both acts are administered by the USFWS. The first act protects migratory birds from <i>unlawful taking</i> – defined as wounding, killing, trapping, and/or capturing. The second act protects the bald eagle and the golden eagle by prohibiting, except in

Key Federal Legislation That Could Affect Carbon Sequestration Projects (Vine, 2003)	
	<p>specified conditions, their taking, possession, and commerce. In January 2001, an Executive Order was issued to further protect migratory birds by requiring federal agencies that take actions having a negative effect on these populations to develop and implement a Memorandum of Understanding (MOU) to promote their conservation (Executive Order 2001).</p>
<p>Executive Order on Invasive Species (EOIS 1999)</p>	<p>Federal resource agencies are required by a February 1999 Executive Order (Executive Order 1999) to develop invasive species management strategies to include prevention, response, and control and monitoring programs, as well as restoration of native species and habitat conditions in invaded ecosystems. The Executive Order created an Invasive Species Council charged with preparation of a National Invasive Species Management Plan.</p> <p>Invasive species are increasing, joining threatened and endangered species as an issue of concern to natural resources agencies. Invasive species have risen to prominence because they have been implicated in the majority of cases where native species have become endangered or extinct. The process of land conversion, in combination with increased air emissions, has transformed native ecosystems in a manner that favors the invasion of many exotic plant species. As a result, many native populations of terrestrial plant species are reduced or eliminated, resulting in subsequent declines in animal species dependent upon them.</p>