Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges

Prepared for:

INGAA Foundation

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The report states that there is uncertainty whether CO_2 pipelines will qualify as Master Limited Partnerships (MLPs). Law restricts MLPs to shippers of depleting resources. Thus, to attain MLP status, some legislation would be required (pages 10, 88, and 92). Since publication, Congress has addressed this issue.

Until late 2008, the term qualifying income was defined to include: “income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber).” 26 U.S.C. § 7704(d)(1)(E). The law was amended by the Energy Improvement and Extension Act of 2008, Pub. L. 110-343, div. B, section 116 of which inserted the term “industrial source carbon dioxide” prior to the phrase “and timber”.

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Acronyms

4P	ICF's four pollutant case in Integrated Planning Model runs where the four pollutants are SO_x, NO_x, H_g, and CO_2.
BIA	Bureau of Indian Affairs
BLM	Bureau of Land Management
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CERC	Certified Emission Reduction Credits
CFS	Clean Fuel Standard
CO_2	Carbon dioxide
CRS	Congressional Research Service
DOE	Department of Energy
DOT	Department of Transportation
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EU	European Union
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FPA	Federal Power Act
FS	Forest Service
GAO	General Accounting Office
GeoCAT	Geosequestration Cost Analysis Tool – an ICF model used to estimate sequestration costs
GHG	Greenhouse gas
H_2S	Hydrogen sulphide
Hg	Mercury
ICO_2N	Integrated CO_2 Network, a proposed carbon capture and storage system for Canada sponsored by a number of major Canadian resource companies
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
INGAA	Interstate Natural Gas Association of America
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
Kt	Kilotonne, 1,000 metric tons
KWh	Kilowatt hour
Mg/L	Milligrams per liter

MPa	Megapascal, about 145 pounds per square inch
MT	Million tonnes. A million tonnes of CO_2 is approximately 18.9 billion cubic feet of gas at standard conditions.
NATCARB	National Carbon Sequestration Database and Geographic Information System
NEB	National Energy Board (Canada)
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGCC	Natural gas combined cycle
NOx	Nitrogen oxides
O&M	Operations and maintenance
OOIP	Original oil in place
PHMSA	Pipeline and Hazardous Materials Safety Administration
PNNL	Pacific Northwest National Laboratory
PPI	Producer price index
psi	Pounds per square inch
R&D	Research and development
RGGI	Regional Greenhouse Gas Initiative
SO_2	Sulfur dioxide
SOx	Sulfur oxides
STB	Surface Transportation Board
TDS	Total dissolved solids, usually expressed in parts per million
Tonne	Metric ton
VER	Verified emissions reductions
WCSB	Western Canadian Sedimentary Basin

Executive Summary

E.1 Purpose and Scope

This study focuses on the pipeline infrastructure requirements for carbon capture and sequestration (CCS) in connection with compliance with mandatory greenhouse gas emissions reductions. The major conclusion of the study is that while CCS technologies are relatively well defined, there remain technological challenges in the carbon capture and sequestration phases, and less so in transportation. Carbon capture is the most significant cost in the CCS process.

The study forecasts that the amount of pipeline that will be needed to transport CO_2 will be between 15,000 miles and 66,000 miles by 2030, depending on how much CO_2 must be sequestered and the degree to which enhanced oil recovery (EOR) is involved. The upper end of the forecast range is of the same order of magnitude as the miles of existing U.S. crude oil pipelines and products pipelines.

While there are no significant barriers to building the forecasted pipeline mileage, the major challenges to implementing CCS are in public policy and regulation. Because a CCS industry can evolve in several ways, public policy decisions must address key questions about industry structure, government support of early development, regulatory models, and operating rules. Such issues must be resolved before necessary investments in a CCS pipeline system can be made.

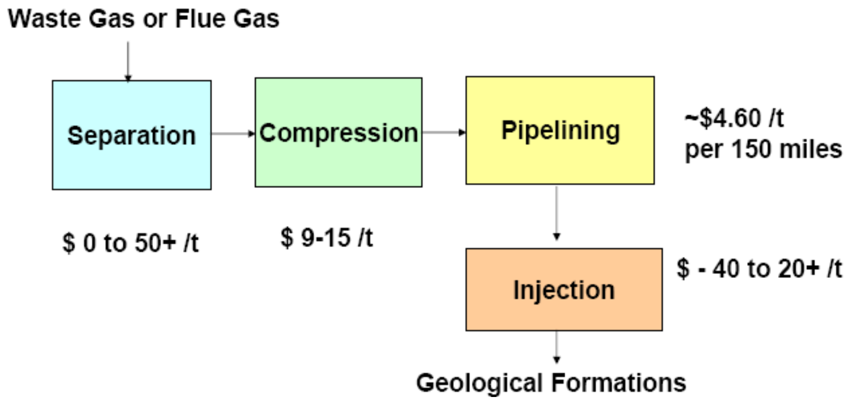
Carbon capture and storage (CCS) consists of the separation of carbon dioxide (CO_2) from industrial and power plant sources, transport to a storage location and long-term isolation from the atmosphere. The principal technical, economic and regulatory challenges of CCS are significant for the capture and storage phase of the process and considerable research into these areas is ongoing. By contrast little analytical work has focused on the pipeline system for transporting CO_2 from capture sites to storage sites. The INGAA Foundation Inc. (Foundation) commissioned this study to provide some information and insights on the size, configuration, costs, timing, commercial structure, and regulation of U.S. and Canadian pipeline systems to transport CO_2.

E.2 Findings on CCS Technologies and Costs

- The three steps in carbon capture and geologic storage are 1) CO_2 capture and compression, 2) pipeline transportation, and 3) underground storage.
- While many of the underlying technologies involved in CO_2 capture are mature, their use in the circumstances and scale needed for CCS carries considerable technological and commercial risks.
- Coal power plants will dominate the proposed CCS projects in the future.
- The major components of costs are in the capture/compression and storage. The capture component of CCS is the most technologically challenging and uncertain. Depending on the quality of the CO_2 stream, capture costs range from

nothing to over $50/tonne. Compression costs add $9 to $15/tonne. Transportation of CO_2 by pipeline is a mature technology and should not see significant change over the next 20 years. Geologic storage costs vary depending on whether the site is an enhanced oil recovery site, where costs are negative, or is one of various types of underground rock formations for which geologic storage costs are a few dollars per tonne.

Figure E-1 Generalized CCS Components and Cost ($/tonne)



Note: Pumping costs are included in pipelining..

- CO_2 pipelines currently restrict the chemical composition of fluids they transport. The most important limit is the amount of water since an excess amount will produce carbolic acid that corrodes standard carbon steel.
- The types of geologic formations suitable for CO_2 are depleted natural gas and oil reservoirs, saline aquifers, coal beds, and shales.
- Despite little experience in large scale geologic storage of CO_2 in the United States, developments at the Sleipner in the North Sea, In Salah in Algeria, and Weyburne in Saskatchewan have been successful.
- To give a sense of scale, the estimated geological storage capacity in the Lower 48 states is equivalent of over 450 years at recent U.S. GHG emissions rates. The Western Canadian Sedimentary Basin of Canada has a partially estimated geological storage capacity of over 100 years at recent Canadian GHG emissions rates. The full geologic storage capacity in Canada may be about 2,000 years equivalent.

Table E-1 Estimated Geologic Storage Capacity (million tonnes)

	Lower 48 States	Canada
Enhanced Oil Recovery	**17,000**	**1,000**
Depleted Oil and Gas Fields	**110,000**	**2,702**
Coal and CBM	**51,000**	**5,000**
Shale Formations	**107,000**	**0**
Deep Saline-filled Basalt	**100,000**	**0**
Deep Saline Reservoirs	**2,990,000**	**60,730**
Total	**3,375,000**	**69,432**

Note: Canadian data reflect partial assessments.

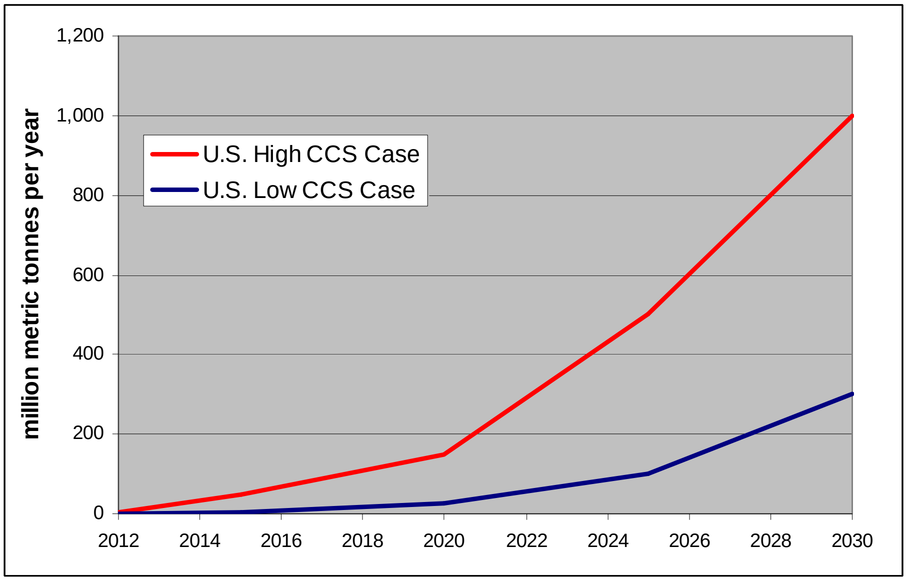
E.3 Findings on Carbon Reduction Policies and Demand for CCS

- Well over a dozen different proposals to control GHGs have been considered by the U.S. Congress. Some of the key aspects of the proposals include the following:
  - ➢ Most take a multi-sector, market-based approach using either a carbon tax or a cap and trade program to limit and regulate many or all segments of economy.
  - ➢ The most recent proposals target a 60% to 80% reduction in U.S. GHG emissions by 2050.
  - ➢ Many bills encourage the development of new technologies like CCS through R&D programs and financial incentives.
- The bills differ on what would be the point of regulation – upstream or downstream – and what entities might be covered or exempted in terms of emission volume.
- The widespread application of CCS will depend on the technology's maturity, costs, volume potential, regulatory framework, environmental impacts, public perception of safety, and other mitigation options. The critical elements of the regulatory framework that affect CCS include:
  - ➢ Appropriate treatment of CCS within the GHG regulatory structure: Some proposals include broader recognition for CCS while others explicitly include only certain CCS applications. Beyond basic recognition of CCS in the GHG programs, issues include how much of the stored CO_2 will receive GHG credits and how would any leakage be detected, measured and accounted for in the crediting mechanism?

- The level of control mandated: The sooner and deeper the cuts in CO_2 emissions are required, the higher will be the allowance prices and the financial incentives for CCS.
- Permitted use of offsets: To the extent that large numbers of international and domestic offsets are permitted, the less pressure there will be on reducing domestic power plant and industrial emissions through CCS and other means.
- Financial incentives for CCS: CCS will be boosted by the allocation of "bonus allowances" and other financial incentives. These may be critical in the early phases of a GHG program when the value of allowances alone is unlikely to provide the economic incentives required for CCS.
- Incentives for other GHG mitigation options: Large incentives for energy conservation, renewables and nuclear power may make CCS look less attractive in some instances.
- Safety valve prices: If safety valve prices are set low, adequate incentives for CCS may be delayed.
- The legal and regulatory regime for geologic storage (GS): There are many legal and regulatory issues related to the ownership of pore space, facility siting, construction, operation, monitoring, and closing of GS facilities that will affect when, where, and how much GS capacity is built.
- Determination of who will carry the long-term responsibility for CO_2 storage sites.

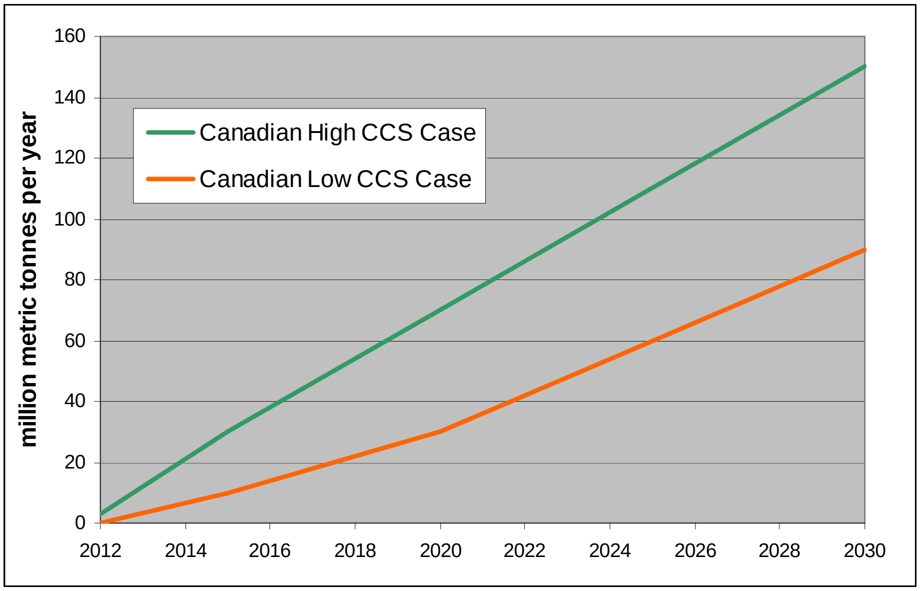
• EIA and other forecasters project a wide range of potential for CCS volumes based on the ultimate regulatory framework described above and various technological and economic factors.

Figure E-2 CCS Potential for U.S. Used for this Study



- For the U.S., the High Case developed for this report anticipates 1,000 million tonnes per year of CCS by 2030 while the Low Case has 300 million tonnes per year by that date. These numbers can be compared against U.S. CO_2 emission from coal power plants which are approximately 2,000 million tonnes per year. Hence, the High Case and Low Cases are roughly equivalent to having 50 percent and 15 percent respectively of the existing U.S. coal plant capacity operated with CCS by 2030.
- Much of the expected CCS in Canada would be in the oil and gas production industry, in particular, emissions related to oil sands production and natural gas processing in Alberta and British Columbia. The overall level of CCS is subject to the same sorts of uncertainties as in the U.S. The Canadian High and Low Cases adopted for this study range from 30 million to 70 million tonnes per year by 2020, respectively. By 2030 these values are 90 to 150 million tonnes per year, respectively.

Figure E-3 CCS Cases for Canada Adopted for This Study



E.4 Findings on CO_2 Pipeline Network Requirements

- It is expected by many of the observers interviewed for this report, that early CCS projects will tend to be situated where suitable injection sites can be found near the CO_2 source so that relatively short, dedicated pipelines between plants and the nearby storage sites can be built. Some such projects may be undertaken by a regulated utility, and will be under the jurisdiction of the relevant regulatory commission.
- It is further expected that as more CCS projects are developed incorporating power plants where no suitable storage site is nearby, projects will increasingly connect multiple plants to storage sites over greater distances. The sharing of pipeline capacity among plants can help reduce the network mileage on average (averaged per CO_2 source). Early and late projects may have the same average mileage per source.
- This report presents four cases to estimate the U.S. CO_2 pipeline infrastructure required, based on the high and low expectations about CCS and the extent to which CO_2 is used for EOR. The estimates are very general and dependent on many unknown variables.
- The U.S. High CCS Case results in additions of 20,610 miles of CO_2 transmission pipeline by 2030, when EOR use of CO_2 is small in scope, and additions of 36,050 miles when EOR use of CO_2 is greater (**Figure E-4**). The cost of constructing the new CO_2 pipeline for the High CCS Case ranges from \$32.2 billion to \$65.6 billion by 2030 (**Figure E-5**). These cost estimates are based on recent historical average costs that are weighted heavily toward gas pipeline systems built in relatively low cost regions. Because construction costs

vary greatly based on the terrain through which the pipeline is built and the prevailing regional materials and labor costs, actual costs for a CO_2 system may be much greater than this.

- The U.S. Low CCS Case produces a range of new CO_2 pipeline requirements by 2030 of 5,900 to 7,900 miles depending on the degree to which longer distance transport to EOR sites takes place (**Figure E-4**). The cost of this new pipeline would be between $8.5 billion and $12.8 billion (**Figure E-5**).

Figure E-4 Cumulative Miles of U.S. Pipeline

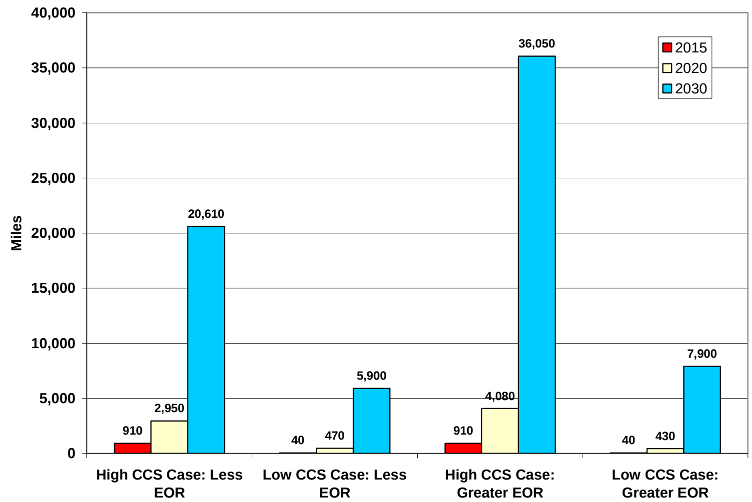
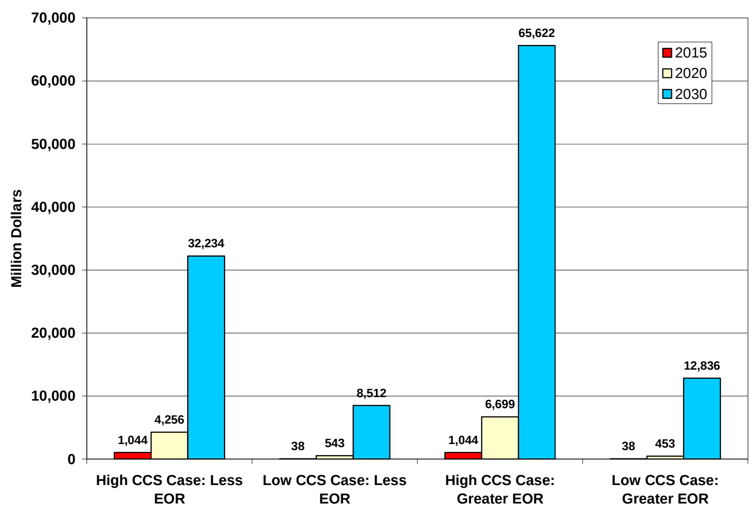


Figure E-5 U.S. CO_2 Pipeline Cumulative Capital Cost (US$)



- The costs of compressors and pumps in the U.S. for the High CCS Case range from $23.9 billion to $24.6 billion. The costs in the Low CCS Case range from $7.17 billion to $7.27 billion.

- In the High CCS Case for Canada approximately 3,650 miles for CO_2 pipeline would be needed by 2030 at a cost of US$7.4 billion. (**Figures E-6** and **E-7**)
- The Low CCS Case for Canada of approximately 2,060 miles of CO_2 pipeline would be needed by 2030 at a cost of US$3.9 billion.
- Canadian compression and pumping requirements would cost from US$3.6 billion to US$2.2 billion by 2030.

Figure E-6 Cumulative Miles of Canadian CO_2 Pipeline

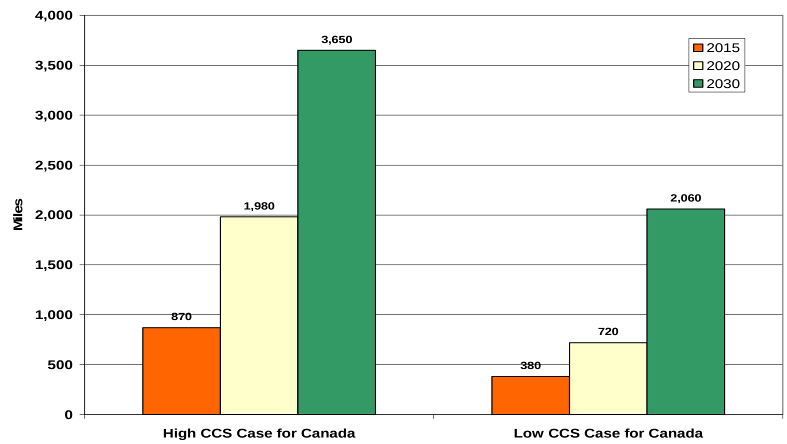
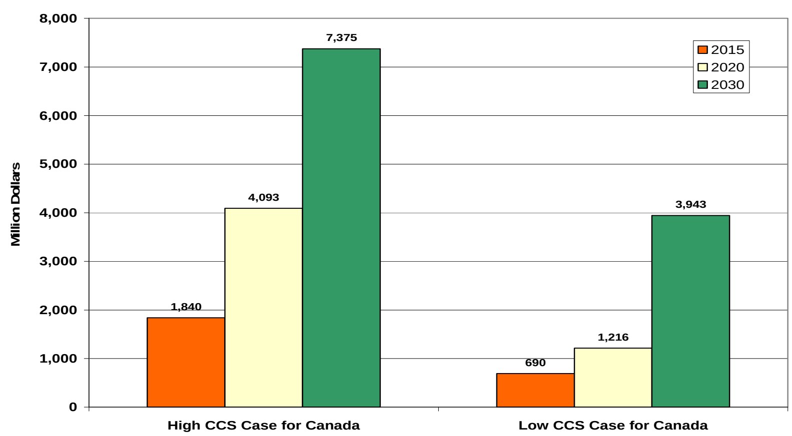


Figure E-7 Canadian CO_2 Pipeline Cumulative Capital Cost (US$)



E.5 Findings on CO_2 Pipeline Commercial Structures and Regulatory Frameworks

Table E-2 summarizes the commercial structures and regulatory frameworks for oil and gas pipelines and CO_2 pipelines.

- There is no definitive federal legal and regulatory framework set up for CO_2 pipeline siting and rate regulation. Potential analogues are the oil and natural gas regulatory systems.

- There is no economic regulation of CO_2 pipelines since the Surface Transportation Board (STB) and the Federal Energy Regulatory Commission (FERC), assert they lack jurisdiction.
- Many current CO_2 pipelines operate as private carriers. In such cases, the pipeline owner owns the CO_2 in the pipeline and the CO_2 is ultimately sold to a third-party for EOR.

Table E-2. Regulatory Framework: Oil, Natural Gas, and CO_2 Pipelines

Element	Oil Pipelines	Natural Gas Pipelines	CO_2 Pipelines
Rates Regulation Authority (Interstate)	FERC	FERC	None (Possibly STB)
Regulatory Regime	Common Carriage	Common Carriage / Contract Carriage	Private, Contract or Common Carriage
Ownership of Commodity	Mostly third-party ownership	Mandated that interstate pipelines only transports gas owned by others.	Common for CO_2 owned by pipeline owner / third-party
Tariffs / On-going regulatory oversight	Yes - rates are approved by FERC and increase indexed to PPI +/- an increment	Yes - Rates are periodically set by rate cases before FERC	No - STB would only look at rates if a dispute is brought before it.
Rate disputes	Every five years the increment to PPI is modified.	Rare for disputes outside of rate cases. However they can be brought before FERC	Uncommon due to ownership relationships and prearranged deals
Siting	State and local governments	FERC	State and local governments
Safety	PHMSA	PHMSA	PHMSA
Market Entry and Exit	Unregulated entry and exit	Need approval for both entry (construction) and exit (abandonment)	Unregulated entry and exit
Product Quality	"Batch" modes transport different products at different times.	Specifications individually set in tariff approved by FERC	No Federal Regulations*
Posting information	Tariff information is available on-line	Daily operational and tariff information is available on-line	None Required
Eminent Domain	Yes - Varies by state. More often if pipeline is a common carrier.	Yes	Varies by State Law

PPI = Producer Price Index

- Current CO_2 pipelines do not create or publish rate tariffs; rather rates are negotiated.
- CO_2 pipeline oversight for construction and operation safety falls under the jurisdiction of the Pipeline and Hazardous Materials Safety Administration

(PHMSA), a part of the Department of Transportation's (DOT) Office of Pipeline Safety.

- In some states certifying that the pipeline is in the public's interest is a prerequisite to the pipeline company receiving the right of eminent domain. In Texas the pipeline must be a common carrier to obtain eminent domain powers.
- The number of state, local, and federal permits necessary for pipeline construction will vary by route. There is no overall federal agency permit necessary but possible Federal permits that may be required depending on various jurisdictions across federal lands and U.S. borders or waters.
- Several alternative ownership and organizational structures have been suggested for CCS projects.
    - On-site storage model, where the producer stores CO_2 at the plant site or very nearby. Pipeline ownership and operation are integrated with the CO_2 production facility.
    - Project ownership model, where a producer enters into a partnership or long term contract with a storage site developer and pipeline operator (who may be the same entity) for transportation and storage.
    - Municipal solid waste model, where a producer contracts for CO_2 removal services with an independent collector and storage site provider.
    - Government or public utility ownership model where an independent corporation collects and stores CO_2
- Many CO_2 pipelines like natural gas and oil pipelines are Master Limited Partnerships (MLP). It is questionable whether CCS pipelines will qualify for MLP status and this may affect the industry development.
- The two broad regulatory concepts for pipelines are common carriage and private contract carriage. Common carriage presents problems for CO_2 producers who cannot tolerate pro rationing of pipeline capacity. However, most agree that contract carriage would be accompanied by open access rules.
- Most observers see a role for the federal government in continuing its safety regulation and in initiating a centralized environmental review and permitting process.
- Most observers have given little thought to rate structures or regulation of CO_2 pipelines. Those who have are strongly in favor or bilateral, market-based rates.
- Other major issues about which there are divergent views include
    - Ownership of CO_2 and liability for local storage impacts (e.g., effects on ground water)
    - Whether there should be federally mandated CO_2 quality standards
    - The role of government in financing, ownership, subsidizing CCS infrastructure

- Preferred financing models for CCS projects
- Which agency should regulate a national pipeline system

The major issues of regulatory design questions are summarized in **Table E-3** below.

Table E-3 Pros and Cons of Federal Regulatory Options for CO_2 Pipelines

Area of Potential Federal Regulation	Pros	Cons
1. Federal jurisdiction for commercial regulation in one agency	**Current confused state of affairs may not support the large potential CO_2 pipeline investments needed in next 20 years.**	**Although some clarification by Congress may be inevitable, objections may be raised by states and special interest groups (industry, environmental, local government, etc.).**
2. Economic Regulation, Rates	**Provide more certain costs for shippers and adequate returns for pipelines.**	**May hinder early CO_2 pipelines' profits from innovative contract terms with shippers given that volume flows will be uncertain.**
3. Common Carriage Regulation	**Ensure access for all CO_2 producers.**	**Where capacity is prorated, may not provide assurance of adequate disposal of captured CO_2**
4. Private Contract Carriage	**Would provide performance assurance, especially for first movers, and provide contract commitments for financing.**	**May reduce access to the system.**
5. Access to Pipeline Capacity	**Requiring open access through common carriage would encourage fewer pipelines to be built, better economies of scale.**	**Economic incentives can lead to optimally sized pipelines in any case. If pipeline developers or shippers want to tie up capacity for themselves (e.g. to support CCS projects planned for the future) they should be able to do so.**
6. Federal Lead for Environmental Reviews (e.g., Hackberry for LNG terminals)	**Will reduce burden to pipeline developers and make CCS more economically viable.**	**Would upset state officials and lead to backlash among citizens against CO_2 pipelines and CCS.**
7. Federal Eminent Domain	**May be needed to improve planning and system wide design and operating efficiencies.**	**May create backlash among property owners. Trade off for ED might be impractical rate regulation.**
8. Federal Corporation for Storage Development and Operations	**Would provide a federal commitment towards a broadly social goal.**	**May stifle private sector opportunities and depending on how structured could result in political considerations driving decision making.**
9. Market Entry and Exit Permission for Interstate CO_2 Pipelines	**Would likely be tied to other regulations. Incentive to regulate might be to limit environmental foot prints of similar projects that can be consolidated.**	**No reason to restrict entry or make it more burdensome.**
10. Product Quality	**Federal standards may help reduce environmental concerns. Would allow linking of separate systems in the long-run.**	**Might restrict most the economic choices (e.g. Oxy-firing of low-sulfur coals without an FGD). Work-around might include a "clean CO_2" spec for EOR and a "dirty CO_2" spec. In the long run pipeline quality specs may have to be tied to EPA underground CO_2 injection rules.**

1. Introduction

1.1 Study Background and Objectives

One of the major strategies identified for reducing future carbon dioxide (CO_2) emissions released to the atmosphere is its capture and storage in underground geologic formations. Carbon capture and storage (CCS) has been shown by several studies undertaken by the Energy Information Administration as well as by others to be a viable, if not critical compliance option under any comprehensive greenhouse gas (GHG) reduction policy. The technical challenges of CCS are significant both in the capture of CO_2 and how and where to sequester it. Considerable research into these areas is ongoing. By contrast, the task of transporting CO_2 has received less attention. It is generally accepted that a pipeline network will be needed to transport CO_2 from the point of capture to the point of storage. However, there has been little examination of the size, configuration, commercial structure and regulation of a national pipeline system to accomplish this.

Congressional interest and consideration of CCS also has focused on the capture and storage issues. Congress recognized the need to consider the transportation issues and, as a result, the Congressional Research Service (CRS) has published three reports on various aspects of CO_2 pipelines. In 2007, CRS issued a report on the emerging policy issues, providing an overview of the challenges faced by developers of CO_2 pipeline infrastructure. In 2008, the CRS issued two reports that addressed jurisdictional issues and network needs and costs.[1] Collectively these reports provide a good overview of the complexities surrounding the design of a CO_2 pipeline network – technical, economic, commercial and governmental.

The natural gas pipeline industry is frequently mentioned as a model for what a CO_2 pipeline network might look like since the North American natural gas pipeline network interconnects thousands of natural gas distribution companies, power plants, and industrial facilities with natural gas producing basins. The technology, scope, operations, commercial structure, and regulatory framework that characterize natural gas pipelines appear to be useful analogues for a CO_2 pipeline system. It can be expected that some additional gas pipeline companies beyond those that currently transport CO_2 for enhanced oil recovery (EOR) projects may expand into the CO_2 transportation business. At the same time, it has to be recognized that the investment needed to support a national CO_2 transportation network will require significant capital and may entail competition for the same material and manpower resources as that of the natural gas and oil pipeline industries.

[1] See these CRS reports: "Carbon Dioxide (CO_2) Pipelines for Carbon sequestration: Emerging Policy Issues," April 19, 2007, by P. Parfomak and P. Folger; "Regulation of Carbon dioxide (CO_2) Sequestration Pipelines: Jurisdictional Issues," Jan. 7, 2008, by A. Vann and P. Parfomak; and "Pipelines for Carbon Dioxide CO_2) Control: Network Needs and Cost Uncertainties," Jan. 10, 2008, by P Parfomak and P. Folger.

Thus, the purpose of this study is to develop a better understanding of how a CO_2 pipeline network will develop, examine the implications for the natural gas pipeline industry and where appropriate, recommend policies and a regulatory framework that will support the development of a viable CO_2 transportation system. In this report we address the following:

- The level and timing of demand for CCS under alternative scenarios of development.
- Alternative scenarios for the configuration and temporal build out of a CCS transportation network given the geographic location of storage sites and CO_2 sources.
- The potential costs and requirements for new pipe, compressors, pumps and other equipment for CO_2 pipelines.
- An elaboration of the regulatory questions that must be addressed for the development of a CO_2 network, including,
    - the suitability of the existing regulatory framework
    - the practical and legal issues of using existing rights-of-way
    - liability associated with transportation and injection both for safety and for leakage
- Potential future regulatory framework for CO_2 pipelines

The study has been undertaken along three lines of inquiry. The technical and economic tasks have focused on the demand for storage and the cost of developing a pipeline infrastructure consistent with that demand. ICF reviewed existing studies and used its proprietary Integrated Planning Model (IPM®) to estimate the volume of CO_2 that would be economically captured and sequestered under alternative scenarios of market development, depending on the scope of the regulations. The third line of inquiry has focused on the regulatory issues and includes the results of both a literature survey and interviews with knowledgeable people involved in policy and commercial development.

1.2 Overview of the Report

Section 2 provides an overview of CCS technology. We examine the key technological challenges of CCS broadly, but turn to the issues directly related to CO_2 pipeline design and cost. Section 3 examines the implications of alternative policy scenarios on the amount of CO_2 that would be sequestered. This is where we present the results of ICF's IPM® and other modeling of alternative policy scenarios. Section 4 integrates the technical and policy outlook to develop alternative infrastructure development scenarios, with alternative network design and cost implications. Section 5 turns to the broad regulatory questions after first considering the commercial structures and issues that precede regulation. Here we report the findings of our literature review and interviews. Section 6 summarizes the regulatory options for CO_2 pipelines.

2. Technology Overview

2.1 Introduction

Carbon capture and storage consists of the separation of CO_2 from industrial and power plant sources, transport to a storage location and long-term isolation from the atmosphere. Potential storage methods include storage in geological formations such as depleted oil and gas fields, unminable coal beds and deep saline reservoirs. CO_2 storage that takes place underground is often referred to as geologic storage or geosequestration. The use of CO_2 for enhanced oil recovery (EOR) is an example of geosequestration. In addition to geosequestration, it is also possible to store CO_2 in the oceans by direct release into the ocean water column or injection onto the deep seafloor and by fixation of CO_2 into inorganic carbonates.

CCS technology is one of several mitigation options to reduce atmospheric greenhouse gas concentrations. Other mitigation options include energy efficiency improvements, the switch to less carbon-intensive fuels including biofuels, nuclear power, renewable energy sources, enhancement of biological sinks, and reduction of non-CO_2 greenhouse gas emissions. Analysis conducted by EIA and others has shown that adoption of CCS in the U.S. will be important to reduce overall mitigation costs and increase flexibility in achieving greenhouse gas emission reductions. The widespread application of CCS in the U.S. and around the world would depend on the technology's maturity, costs, volume potential, regulatory framework, environmental impacts, public perception of safety and the attractiveness of alternative mitigation options.

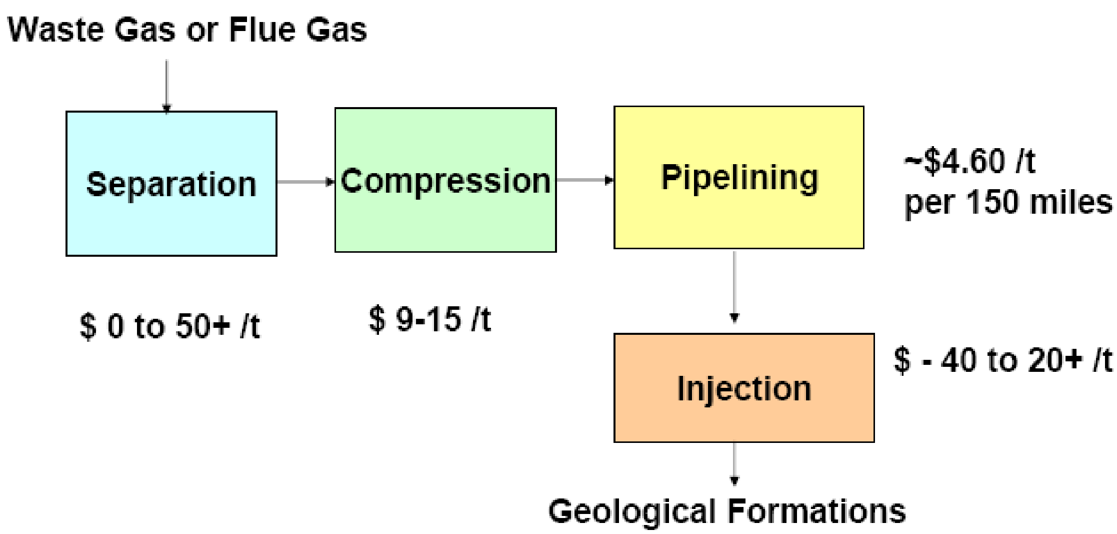
Although large scale geologic sequestration of CO_2 has not yet begun in the U.S., several projects such as Sleipner in the North Sea, In Salah in Algeria, and Weyburne in Alberta have achieved success in recent years. At these sites, CO_2 is being sequestered and technologies to monitor the process have proven effective. As of 2008, the U.S. Department of Energy (DOE) is supporting approximately 25 storage pilot projects around the country and plans to start a number of relatively large scale pilot projects within coming years. A summary table of several of these projects is presented in **Appendix A**.

In general terms, the components and economics of CCS with geosequestration are shown in **Figure 2-1**. The capture component will vary based on the source of the CO_2, method of capture, material and construction costs and energy prices. A small volume of high-purity CO_2 streams produced in the industrial sector can be captured at near-zero costs and then dehydrated and compressed for approximately $15 per tonne. However, the big volume of emissions from coal power plants will be captured and compressed for incremental cost ranging from $31 per tonne for a new integrated gas combined cycle (IGCC) power plant, $51 per ton for new pulverized coal plants and $56 on up per tonne for existing coal power plants.

The transportation component will vary based on volume and distance. CO_2 from industrial sites that moves over a pipeline network in which some aggregation of volumes from several sources is possible would have a generalized cost of $4.60 per 150 miles (**Figure 2-1**).

Cost of geologic storage would depend on the type of formation into which the CO_2 is to be injected, site specific parameters (e.g. drilling depth, injection rates per well, storage capacity per well, etc.) and regulatory and legal regime under which the site will be permitted, constructed, operated, closed and monitored after closing. In cases where the CO_2 can be used for enhanced oil recovery it might be sold to oil companies for a price of $30-40 per tonne. The sales price for EOR will depend on oil prices, the other (non-CO_2) costs of EOR and the degree of competition among CO_2 sellers. The economics of geosequestration into a saline reservoir will vary widely from site to site but are expected to cost $3 to $7 per tonne at the favorable locations that are most likely to be developed first.

Figure 2-1 Generalized CCS Components and Cost ($/tonne)



Note: Pumping costs are included in pipelining.

2.2 Sources of CO_2 and Other GHG Gases

Figure 2-2 shows the sources of GHG emissions in the U.S. economy from the *2006 U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks* The largest contributions come from power generation (34%), followed by transportation (27%) and industrial fuel combustion (12%). **Figure 2-3** shows U.S. emissions by fuel and sector. Coal-related emissions dominate the power sector, while oil is the source of the transportation sector's GHG emissions.

Figure 2-2 US GHG Emissions-2006

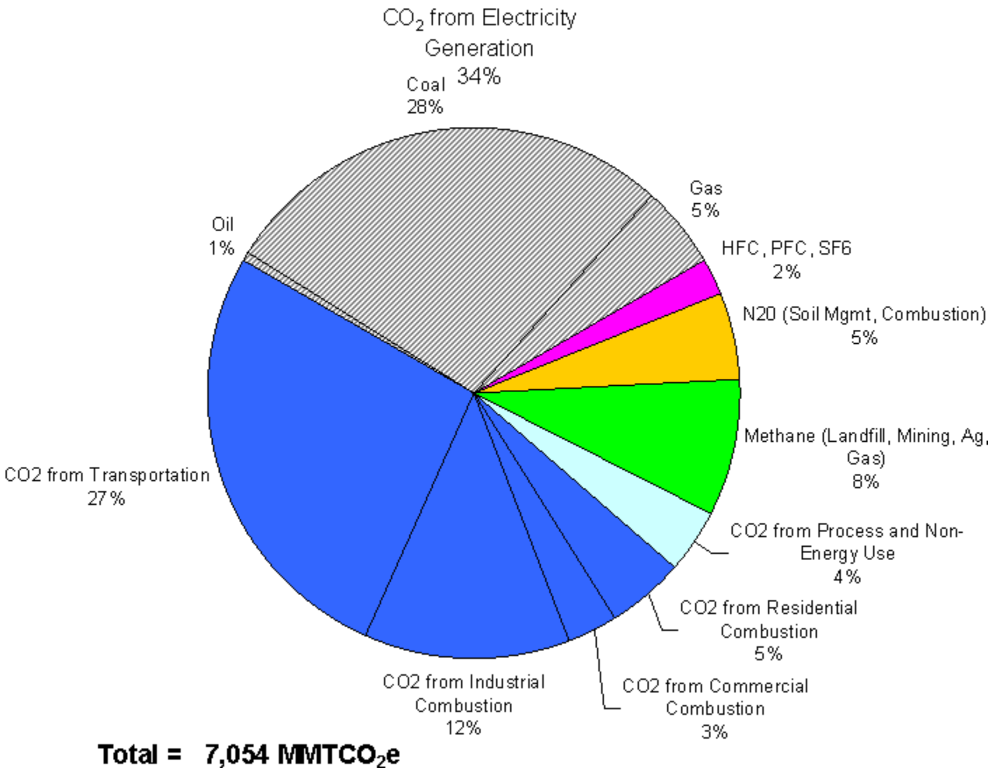


Figure 2-3 Emission by Fuel and Sector-2006

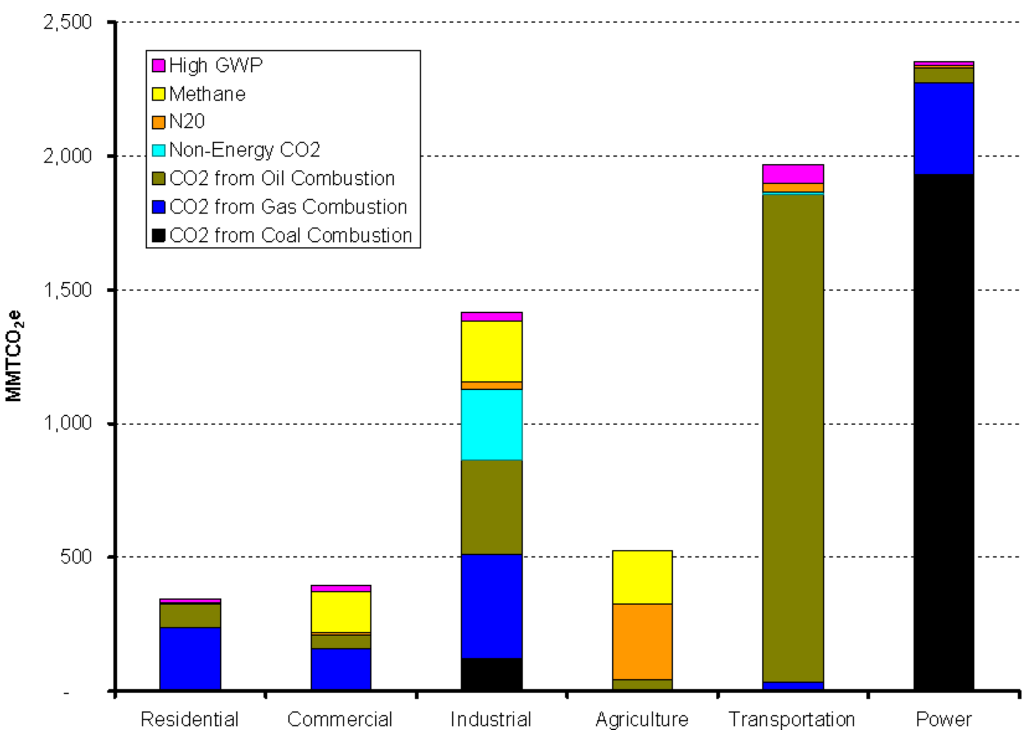
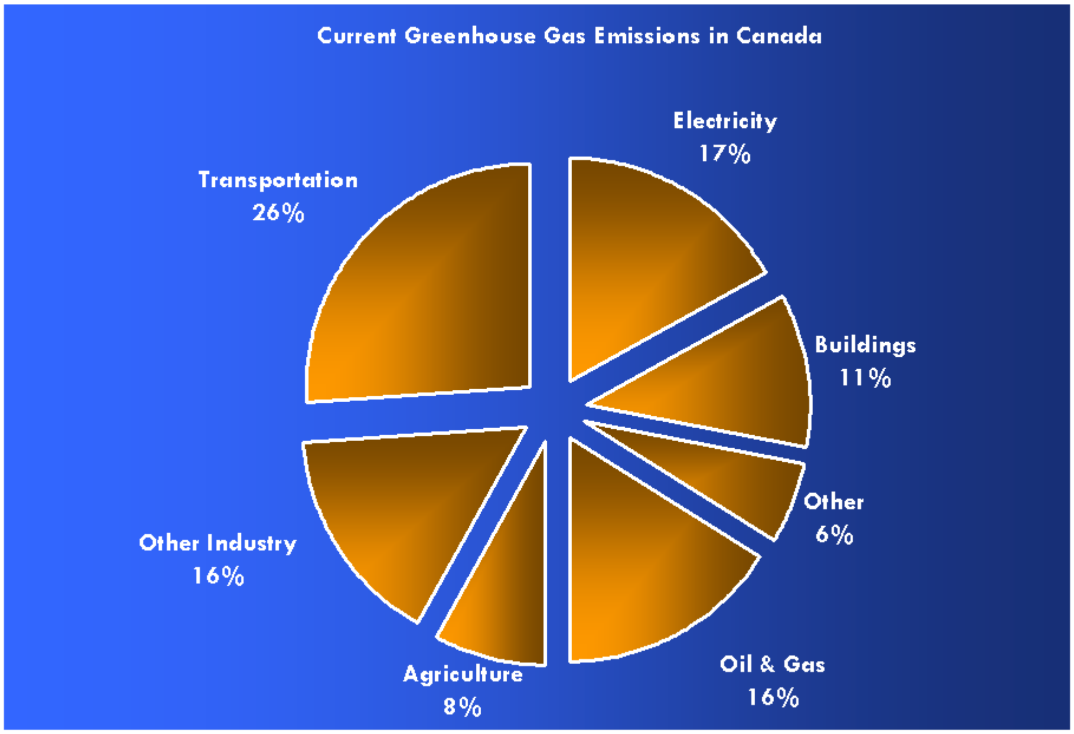


Figure 2-4 illustrates the source of Canada's national and industrial-based GHG emissions. The oil and gas sector is a substantial contributor to Canada's CO_2 emissions and is expected to be the largest source of growth due to oil sands development in Alberta. This is discussed further in section 3.1 of this report.

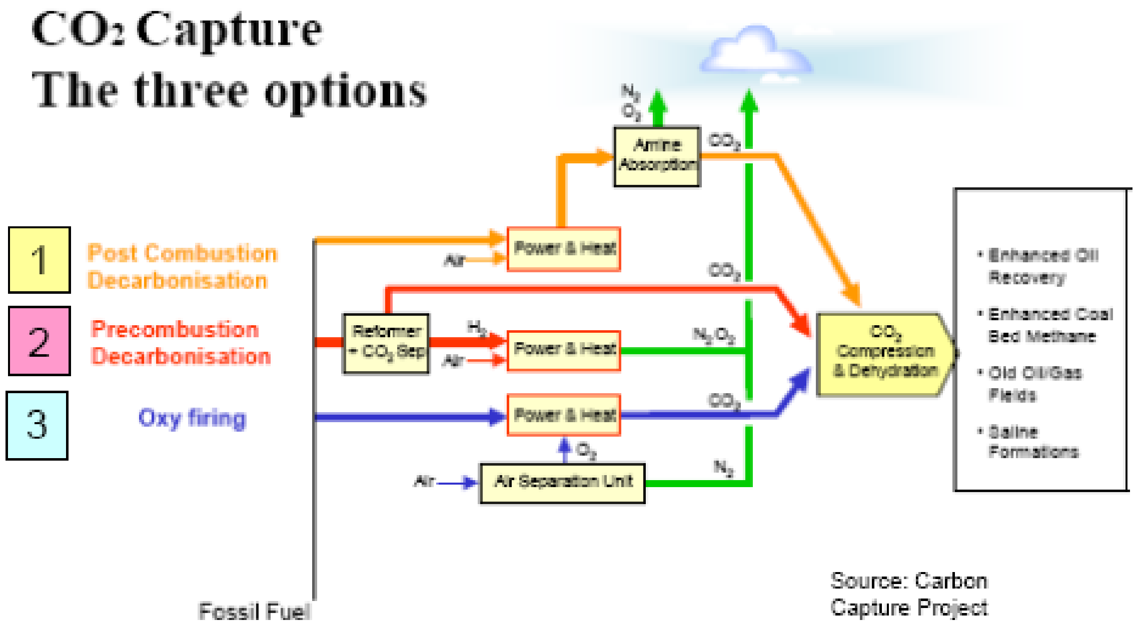
Figure 2-4 Canadian CO_2 Emissions by Source



2.3 CO_2 Capture

CO_2 can be captured from flue gases at industrial facilities and power plants or by capture from CO_2-rich wastes streams from certain industrial process. Three main categories of technology options for capture are illustrated in **Figure 2-5**.

Figure 2-5 Technologies for Carbon Capture



Capture at Power Plants

CO_2 capture at existing power plant facilities and new pulverized coal power plants is most likely to come from **post-combustion capture** using amine or another solvent or from firing fuel with oxygen instead of air. **"Oxy firing"** or "oxyfuel" option involves recirculating flue gases to compensate for lower combustion gas volumes. The same techniques could be used in new power plants or the plants could be built with pre-combustion carbon capture. The most common form of **pre-combustion capture** at power plants is likely to be coal gasification with carbon capture. This involves using a water-gas shift to convert the carbon monoxide in the syngas (containing the two fuels carbon monoxide and hydrogen along with CO_2 and other gases) to hydrogen and then separating out the CO_2.

Capture at Industrial Facilities

The industrial sector could capture and sequester 1) CO_2-rich process gas streams and 2) fuel gases from fossil-fuel combustion. The CO_2-rich industrial streams include those from steam methane reforming at petroleum refineries, ammonia manufacturing, ethanol production and cement kiln operation. Industrial flue gas streams can come from any boiler or process heater burning natural gas, oil or coal. Carbon dioxide from industrial flue gases could be captured using the same post-combustion solvent or oxyfuel processes that could be applied to power plants.

Capture at New Power Plants

Costs for capture and compression of CO_2 at new power plants are shown in **Table 2-1**. The capital construction costs circa 2004 are derived from a 2007 Massachusetts

Institute of Technology (MIT) study of coal options.[2] The costs are shown relative to a base plant (supercritical bituminous coal) without capture. The 2008 costs are calculated by escalating the MIT capital costs by 46 percent to represent recent increases in construction costs. The increased cost in cents per kilowatt-hour of electricity are roughly the $/tonne cost times 0.07. For example, Bituminous Supercritical Pulverized Coal with Post-combustion Amine Capture would add 51 x 0.07 = 3.6 cents per kWh to the cost of electricity the same generating technology without carbon capture.

Table 2-1 Carbon Capture and Compression Costs at New Coal Power Plants ($/tonne relative to new supercritical pulverized coal w/o capture)

Capital Costs	Bituminous Coal IGCC *(Pre-combustion capture)*	Bituminous Supercritical Pulverized Coal *(Post- combustion amine capture)*	Bituminous Supercritical Pulverized Coal (*Oxyfuel*)	Lignite Supercritical Pulverized Coal *(Post- combustion amine capture)*
circa 2004	$24	$40	$30	$44
circa 2008	$31	$51	$38	$56

The capture process is highly energy intensive. In the case of amine capture at a pulverized Coal (PC) power plant, the steam energy needed to regenerate the amine (i.e. drive off the CO_2 so that the amine can be reused) is about 1.75 MMBtu per tonne of CO_2. Additionally, the extra electricity needed to run the extra blowers and process equipments for CO_2 capture comes to 25 to 70 kWh per tonne and the energy needed to compress the CO_2 to supercritical state for transport is about 120 kWh per tonne. Taken all together, these extra energy requirements increase the heat rate of a supercritical PC from 8,870 to about 11,700 Btu per kWh net energy produced.

For pre-combustion capture at Integrated Gasification Combined Cycle (IGCC) plants energy requirements are lower because the capture can be performed using a physical solvent (e.g., Selexol) and the capture is done at higher pressures, necessitating less compression. The total heat rate increase expected for IGCC power plants is from 8,891 to 10,942 Btu per kWh net energy produced.

The cost for capture and compression of CO_2 from existing coal plants is expected to be higher than the cost for new plants due to space constraints and the resultant suboptimal configuration for CO_2 capture and because the energy penalty from the needed equipment will substantially derate the existing plants net output capacity substantially (over 25 percent). For example, a study recently performed for the U.S. DOE estimated 2006 costs to be in the range of $51 (without replacing derated capacity) to $60 (with capacity replacement) per tonne for 90 percent CO_2 capture at a large PC power plant.[3] As shown in **Table 2-2**, at 2008 construction costs these CO_2

[2] The Future of Coal. MIT Press, 2007 http://web.mit.edu/coal/The_Future_of_Coal.pdf
[3] Carbon Dioxide Capture from Existing Coal-fired Power Plants, December 2006, DOE/NETL-401/120106

capture and compression costs for existing coal plants would be approximately $56 per tonne without capacity replacement and $66 per tonne including capacity replacement.

Table 2-2 Carbon Capture and Compression Costs at Existing Coal Power Plants – Bituminous Subcritical Pulverized Coal (Amine Capture) ($/tonne)

Capital Costs	No Replacement of Lost Capacity	With Replacement of Lost Capacity
circa 2006	$51	$60
circa 2008	$56	$66

CO_2 can also be captured at natural gas-fired power plants (**Table 2-3**). The estimated cost for CO_2 capture at new natural gas fired combined cycle unit at 2008 construction costs would be about $75 per tonne when natural gas prices are at $8 per MMBtu.[4] At $12 per MMBtu natural gas prices, the capture and compression rises to $89 per tonne.

Table 2-3 Carbon Capture and Compression Costs at New Gas-fired Combined Cycle Power Plant ($/tonne)

Capital Costs	**Natural Gas @$8/MMBtu**	**Natural Gas @$12/MMBtu**
circa 2004	$62	$75
circa 2008	$75	$89

<u>Industrial Capture: Benfield Process Steam Methane Reformers</u>

In general, the overall cost of CO_2 capture decreases with the increase in CO_2 concentration in the flue gas and waste gas streams. The lowest cost carbon capture is from "Benfield process" steam methane reformers making hydrogen from natural gas at petroleum refineries, ammonia plants, chemical plants and bitumen upgrades. The Benfield process is the traditional method of making hydrogen and involves two (high and then low temperature) shift reaction stages followed by CO_2 removal through chemical absorption (mostly the Benfield potassium carbonate process). The waste stream of about 47 percent CO_2 and 53 percent water vapor and other gases can be dehydrated and compressed to supercritical conditions for a cost that depends on the price of electricity (See **Table 2-4**).

[4] Based on cost and heat rate penalty from: *Cost and Performance Baseline for Fossil Energy Plants*, DOE/NETL-2007/1281

Table 2-4 Dehydration and Compression of High-Purity CO_2 Industrial Waste Gas Streams with Benfield Steam Methane Reformers

	Dollar per Tonne CO2			
Electricity Price $/kWh	Capital	O&M	Electricity	Total
$0.040	$3.19	$1.45	$4.80	**$9.44**
$0.050	$3.19	$1.45	$6.00	**$10.64**
$0.060	$3.19	$1.45	$7.20	**$11.84**
$0.070	$3.19	$1.45	$8.40	**$13.04**
$0.080	$3.19	$1.45	$9.60	**$14.24**
$0.090	$3.19	$1.45	$10.80	**$15.44**
$0.100	$3.19	$1.45	$12.00	**$16.64**
$0.110	$3.19	$1.45	$13.20	**$17.84**
$0.120	$3.19	$1.45	$14.40	**$19.04**
$0.130	$3.19	$1.45	$15.60	**$20.24**
$0.140	$3.19	$1.45	$16.80	**$21.44**
$0.150	$3.19	$1.45	$18.00	**$22.64**

<u>Industrial Capture: Acid Gas Removal Units at Gas Processing Plants</u>

Another source of high- CO_2 gas streams is natural gas processing wherein carbon dioxide (often along with hydrogen sulfide -- another “acid gas”) is removed from the raw natural gas using an amine chemical solvent or a physical solvent such as Selexol. When hydrogen sulfide (H_2S) is not present, the vented gas stream from solvent regenerator in the acid gas removal unit contains a high purity CO_2 that can be dehydrated and compressed to supercritical conditions for a cost similar to those shown in **Table 2-4**.

When CO_2 is present in low concentrations in natural gas, the waste gas from the acid gas removal unit can be combusted with other fuel to convert the poisonous H_2S to sulfur dioxide (SO_2) and then that gas can be vented. When H_2S concentrations are high, one of several sulfur recovery processes are used to remove elemental sulfur. Carbon capture from gas processing plants with H_2S could involve one of several options:

- Inject the CO_2 / H_2S waste gas underground without separation. This is the current practice at several gas plants in Alberta and elsewhere due to the low value of elemental sulfur.
- Reconfigure and operate the solvent process (Selexol) in a two-stage manner that produces a relatively pure CO_2 stream for capture and storage. (The remaining H_2S / CO_2 mix can be processed in whatever is the current manner.)
- Capture the CO_2 at the end of the existing sulfur recovery process. This will involve scrubbing the residual sulfur dioxide out of the tail gas and then recovering the CO_2.

Cement Plants

Cement plants produce a waste gas (a combination of combustion products and process gases) that consists of about 24 percent carbon dioxide. Since coal is a common fuel at cement plants, it might be possible to use coal to supply the needed incremental energy. Costs would vary greatly based on site-specific factors, but are expected to be $80 and higher per tonne of avoided CO_2.

General Flue Gases from Industrial Plants

The combustion products of industrial boilers and process heaters could be captured through use of a post-combustion solvent or by converting equipment to oxyfuel combustion. **Table 2-5** below shows the approximate flue gas composition (at about 12 percent excess air) for coal, oil and natural gas combustion in air.

Table 2-5 Example Flue Gas Compositions (atmospheric combustion, values in mol percents)

Fuel	CO_2	H_2O	SO_2	N_2	O_2	Other	Sum
Coal*	14.5%	8.7%	0.2%	73.3%	2.5%	0.9%	100.0%
No. 2 Fuel Oil	10.8%	13.2%	0.0%	72.6%	2.5%	0.9%	100.0%
N. Gas	8.3%	17.4%	0.0%	71.0%	2.5%	0.8%	100.0%

* Before any flue-gas desulfurization (FGD)

The cost of capturing CO_2 from industrial flue gases depends on the concentration of CO_2 in the gases, economies of scale, the configuration of the industrial facility and the cost of the required energy. The cheapest capture opportunities will be high-concentration, high-volume sources with inexpensive energy sources (for steam and electricity). For large industrial facilities with substantial economies of scale coal flue gases can be captured with an amine process and compressed for costs in the range of $65 to $80 per tonne on up, with the lower end based on use of coal as the fuel to operate the capture equipment. Capture of carbon dioxide from high-volume natural gas and oil flue gases will likely cost $95 per tonne or more with natural gas priced at $8 per MMBtu.

Oxy-firing at Industrial and Power Plants

As with power plants, industrial boilers and process heaters could be run using oxygen instead of air to produce a flue gas with little nitrogen. The CO_2 is separated from water vapor by condensing the water through cooling and compression. Further treatment of the flue gas may be needed to remove pollutants and non-condensable gases (such as nitrogen and argon) prior to CO_2 storage. Depending on various technical, economic and regulatory factors, the flue gases from oxy-firing may have to be treated to remove SO_x before being sequestered

Table 2-6 shows the approximate compositions of flue gases for oxy-firing assuming that five percent nitrogen and four percent argon is left in the oxygen mixture. Separation of oxygen from air can be done by using a cryogenic process, membrane separation or pressure swing adsorption. Higher purity of oxygen can be achieved at extra capital and operating costs. Some of these costs for purer oxygen can be offset by the lower costs of compressing the flue gases since they will contain less nitrogen and argon.

Table 2-6 Example Oxy-fired Flue Gas Compositions (Approximately 82%-75% recirculation, values in mol percents)

Fuel	CO_2	H_2O	SO_2	N_2	O_2	Other	Sum
Coal (no FGD)	74.9%	10.8%	1.1%	5.7%	3.3%	4.2%	100%
Coal (with FGD)	75.7%	10.8%	0.30%-0.02%	5.7%	3.3%	4.2%	100%
Oil	68.9%	16.8%	0.0%	6.1%	3.3%	4.9%	100%
Gas	61.9%	22.2%	0.0%	7.0%	3.3%	5.6%	100%

FGD=flue-gas desulfurization

An oxy-fuel flame is much hotter than atmospheric combustion flames. Oxy-firing will in most instances require that some of the flue gases be recirculated to bring the volume and temperature of gases in the combustor nearer to combustion design parameters. This is certainly true for retrofitting existing industrial and power plant combustors and may be true for new units as well as those not designed to withstand and take advantage of the hotter flames. The compositions of extracted flue gases of **Table 2-6** assume that about 75 percent (coal) to 82 percent (natural gas) of the flue gases are recirculated and 25 to 18 percent are vented or otherwise removed. Note that this recirculated gas will have much of its water vapor removed as it is cooled down so it does not build up as the flue gas is recirculated.

It is possible that FGD recirculated gas from coal combustion also will be put through a flue gas desulfurization unit to remove SO_x. The coal examples in **Tables 2-5** and **2-6** are based upon Illinois Basin bituminous coal with a sulfur content of 2.5 percent by weight. If no FGD unit is used, then the sulfur content of the extracted oxy-firing flue gas will be 1.1 percent instead of the 0.2 percent shown in **Table 2-5** for atmospheric combustion. This may exceed the design parameters of the boiler and force the use of an FGD. If an FGD with 95 percent SO_x removal efficiency is used on the recirculated flue gas, the resulting vented flue gas steam will have just 0.3 percent SO_x or 0.02 percent SO_x if the vented flue gas also goes through the FGD.

The economics of oxy-firing depend on the economies of scale that can be achieved in air separation, the duct work and blowers needed for moving oxygen and the recirculated flue gases, the purity requirements of the final CO_2 stream, and the cost of energy used for air separation. The capital cost increase and the energy use penalty for oxy-firing are very close to that of post-combustion amine capture. However, because the oxy-firing allows nearly all of the CO_2 to be captured versus about 90 percent for the most economic amine system, the estimated cost per tonne CO_2 mitigated for oxy-firing are often lower.

Improving Carbon Capture Technologies

It is possible that new technologies to capture CO_2 could prove to be less expensive than the processes that have been reviewed thus far. Research is ongoing to find better chemical absorption and physical absorption solvents that would require less space for equipment, be less subject to degradation, and use less energy.

Research is also being conducted in membrane separation technologies to remove CO_2. Gas separation membranes are semi-permeable materials that permit the direct passage of CO_2 but retain other molecules. While these systems have not been proven in flue gas service, they have had commercial success in the separation of CO_2 from natural gas at the wellhead. Research is underway to improve the operating life and other performance characteristics of these membranes. Also improved membrane technology could play an important role in reducing the cost of separating oxygen from air. This would reduce the cost of both oxy-firing and pre-combustion capture technologies.

Another promising option is solid physical adsorption which captures CO_2 on a solid material (such as a zeolite) and then releases the captured gas through pressure swing or temperature swing. Pressure swing adsorption (PSA) is a widely used commercial process to separate H_2 from H_2/CO_2 mixtures in H_2 production and in other applications. The problem with using PSA now is that power plant and industrial flue gas pressures are too low to cause CO_2 to adhere to solid materials and the option of pressuring up the gases would add substantially to capture costs. For this reason, research is underway to find materials that would hold and release CO_2 with smaller pressure or temperature swings. Also because zeolite adsorbents for CO_2 separation selectively adsorb water, moisture must be removed in a pretreatment step. One focus of current research is to develop novel adsorbents that are less sensitive to water vapor. There is also a need to develop and demonstrate large-scale vacuum pumps and valves for this removal process.

Flue gas CO_2 capture could also be achieved by simply cooling and compressing the gas stream until the carbon dioxide condenses into a liquid or dry ice. This cryogenic approach is unlikely to ever be economically viable given the energy requirements. However, in the presence of small quantities of water, the CO_2 can be made to condense at a more reasonable temperature and pressure (32^{o} Fahrenheit and 300 psi) in the form of a hydrate, a solid ice-like structure. If conditions are carefully controlled, these CO_2 hydrates can be made to form selectively, leaving other gases behind. Once these gaseous components have been separated, the CO_2 can be regenerated from the gas phase, or possibly sequestered in the hydrate form.

2.4 Geologic Storage of CO_2

Geological storage of CO_2 is accomplished by injecting it in dense form into a rock formation below the earth's surface. Porous rock formations that hold or have previously held fluids, such as natural gas, oil or saline reservoirs, are potential candidates for CO_2 storage. Suitable storage formations can occur in both onshore and offshore sedimentary basins. Coal beds and shales also may be used for storage of CO_2 where it is unlikely that they will later be mined and provided that permeability is sufficient. The option of storing CO_2 in coal beds and gas shales and enhancing methane production is still in the demonstration phase.

At depths below 2,600 to 3,300 feet (800–1,000 meters), CO_2 remains a supercritical fluid with liquid-like density of about 31 to 50 pounds per cubic foot (500–800 kg per cubic meter). This provides for efficient utilization of underground storage space. Under these conditions, the density of CO_2 will range from 50 to 80 percent of the density of water. This is close to the density of some crude oils, resulting in buoyant forces that tend to drive CO_2 upwards. Consequently, a well-sealed cap rock over the selected storage reservoir is important to ensure that CO_2 remains trapped underground.

The injection of CO_2 in deep geological formations involves many of the same technologies that have been developed in the oil and gas exploration and production industry. Well-drilling technology, injection technology, computer simulation of storage reservoir dynamics and monitoring methods from existing applications are being developed further for design and operation of geological storage. Other underground injection practices also provide relevant operational experience. In particular, natural gas storage, the deep injection of liquid wastes, and acid gas disposal (mixtures of CO_2 and H_2S) have been conducted in Canada and the U.S. since 1990 at the megatonne per year scale.

Large-scale geosequestration storage projects in operation now include: the offshore Sleipner natural gas processing project in Norway, the Weyburn Enhanced Oil Recovery project in Canada, which stores CO_2 captured in the United States, and the In Salah natural gas project in Algeria. Each captures and stores one to two million tonnes of CO_2 per year.

CO_2 is also being injected underground at many locations for the exclusive purpose of enhanced oil recovery. Carbon dioxide enhanced oil recovery is one of several methods to increase the production of oil from mature reservoirs whose output is declining under normal production processes. It has been the fastest growing EOR method in the U.S. and currently accounts for about 37 percent of total 2005 U.S. EOR production. The most common CO_2 EOR method is miscible displacement, in which the injected CO_2 dissolves fully in the oil, increasing its volume and reducing its viscosity. This increases the mobility of the oil, resulting in the production of oil bypassed by primary and secondary recovery methods. Typical CO_2 floods, under the right conditions, can yield an additional 7 to 15 percent of original oil in place (OOIP), extending the life of a producing field by as much as 15-30 years. Much of the CO_2

injected for EOR is produced with the oil, from which it is separated and then reinjected. At the end of the oil recovery, the CO_2 can be retained for the purpose of climate change mitigation, rather than vented to the atmosphere. This is planned for the Weyburn project.

EPA Draft Rule for UIC Class VI Wells

The Underground Injection Control (UIC) program is administered by the Federal EPA and the states to address how wells are drilled, operated and monitored for the underground disposal of various industrial fluids, byproducts and wastes. The primary goal of the program is to protect underground sources of drinking water (USDWs). The two major well classes under the UIC program are Class I, which covers non-hazardous and hazardous industrial wastes and Class II, which covers wells used in oil and gas production including produced-water disposal wells, water injection wells, CO_2 injection wells used for EOR and wells used for underground hydrocarbon storage.

In July of 2008 EPA proposed changes to the UIC program that would establish a new Class VI designation for wells injecting CO_2 into saline and other reservoirs for the purpose of long term geologic storage. Wells injecting CO_2 as part of enhanced oil recovery projects would continue to be regulated as Class II wells.

The draft rules specify minimum technical criteria for the geological characterization, fluid movement, area of review and corrective action, well construction, operation, mechanical integrity testing and monitoring, and well plugging, post-injection site care, and site closure. The draft rules are based on the existing UIC regulatory framework with additional new requirements to address the unique nature of CO_2 storage including the corrosive nature of CO_2 mixed with water, the buoyancy of CO_2 and the very large volumes that would be injected.

The draft rules only deal with the geologic storage process and do not touch on the carbon capture step or CO_2 transportation by pipelines or other means. Also, since the draft rules are written under EPA's UIC authority to protect underground sources of drinking water, they do not touch on the issue of atmospheric release of CO_2 or how a geologic storage project would be credited as part of any future GHG regulatory program.

DOE Sequestration Program

The U.S. Department of Energy's carbon sequestration research effort is managed by the National Energy Technology Laboratory in Morgantown, West Virginia. The program has two major components: Core R&D and Demonstration and Deployment.

The field component of the sequestration research is being carried out by seven regional partnerships. These partnerships were formed in 2003 and represent a consortia of private industry and government agencies. This effort is tasked with determining the most suitable technologies, regulations, and infrastructure needs for capture and storage.

There are three phases to the work being carried out by the partnerships:

- Characterization (2003-2005)
- Validation (2005-2009)
- Deployment (2008-2017)

The Characterization Phase involved the geologic analysis that resulted in the development of a National Carbon Sequestration Database and Geographic Information System (NATCARB). The Validation Phase is currently active and involves such activities as validation of reservoir simulation methods, data collection for capacity and injectivity, and demonstration of monitoring technologies. Also being researched are well completion methods, operations, and abandonment approaches.

The Deployment Phase involves the construction and operation of approximately seven relatively large scale sequestration pilot projects. These tests are designed to evaluate the practical potential for commercial scale operations in a range of geological settings over a prolonged period of time. The tests are planned to have an injection period of about four to seven years, followed by a lengthy monitoring period.

The Validation Stage is ongoing at numerous sites around the U.S., and the Deployment Stage is expected to begin injecting CO_2 in 2009, with a significant ramp up involving several projects by 2010.[5] In October, 2006, DOE announced that it will provide $450 million over the next 10 years for field tests in the various regions to validate the results from smaller tests, with an additional cost share of 20 percent from the partnerships.[6]

CO_2 Storage Potential of the U.S.

Over the past several years, DOE and the regional partnerships have carried out an effort to assess and characterize the CO_2 sequestration capacity and potential of the U.S. This effort has resulted in the publication of a large amount of information on potential by geologic setting and basin or state. A large amount of Geographic Information Systems (GIS) data have also been compiled on the geology of sequestration potential.

In 2008, DOE published the most recent version of the *Carbon Sequestration Atlas of the United States and Canada* (NATCARB Atlas).[7] This publication contains maps and data tables documenting their assessment of storage potential in the U.S. Much of the data behind the NATCARB atlas are either available in GIS form or will eventually be made available. The major storage reservoir types are summarized below.

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[5] *Regional Carbon Sequestration Partnerships Annual Project Review Meeting*, DOE/NETL, December 12, 2007.

[6] *Direct Carbon Sequestration: Capturing and Storing Carbon Dioxide*, Congressional Research Service, report RL33801, September, 2007.

[7] *Carbon Sequestration Atlas of the United States and Canada – Second Edition,* U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, November, 2008.

Non-Basalt Saline Reservoirs. Most significant sedimentary basins in the U.S. contain regionally significant saline formations that are potential storage reservoirs. These are typically sandstone lithologies with good porosity, containing formation waters of greater than 10,000 mg/L TDS. Salinity may be as high as several times that of seawater. Thus, the water is unsuitable for drinking or agriculture. Saline reservoirs dominate the assessed potential of the U.S. and worldwide. In addition, because of their wide geographic distribution in the U.S., saline reservoirs are often in close proximity to CO_2 sources, minimizing pipeline transport distance. It is very likely that saline reservoirs will play a prominent role in future geologic storage.

Storage in saline reservoirs has been shown to be effective. The Sleipner field in the North Sea is the first commercial-scale saline reservoir project. Carbon dioxide is separated from the gas stream and re-injected into a reservoir at about 800 meters depth. The rate of injection is 2,700 tons per day or about one million tons per year.[8] It is anticipated that about 20 million tons will eventually be stored. At Sleipner, the plume has been monitored effectively.[9]

DOE has extensively studied saline reservoirs for sequestration. Projects include the Frio Brine pilot in the Texas Gulf Coast and the Mount Simon Sandstone in the Illinois Basin.[10] The Mount Simon is known to have excellent storage potential because of its regional thickness and reservoir characteristics, and because it has been used extensively for natural gas storage in the Midwest.

Depleted Natural Gas Fields and Oil Fields. Depleted natural gas and oil fields can be excellent candidates for CO_2 storage. These represent known structures that have trapped hydrocarbons over geologic time, thus proving the presence of an effective structure and seal above the reservoir. These fields have also been extensively studied, there is a large amount of well log and other data available, and the field infrastructure is already in place. This infrastructure could in some cases be utilized in storage. A potentially problematic aspect of using depleted fields for storage is the presence of a large number of existing wellbores, which can provide leakage pathways. Typically, oil fields are developed with a closer spacing than natural gas fields, resulting in a larger number of existing wells per unit area than in natural gas fields. It is possible that in old fields, the original oil

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[8] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[9] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[10] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss,* Interstate Oil and Gas Compact Commission, January, 2005.

and gas wells may have been completed and then -- at the end of their lives -- plugged and abandoned using sub-standard materials and practices. In such instances the plugged wells will have to be remediated before CO_2 injection can begin at the site. The cost of this process may render an old oil or gas field economically unsuitable.

The In Salah Field in Algeria was the world's first project in which CO_2 is injected at commercial scale into a natural gas reservoir. However, in this case, the natural gas is injected in the lower part of an actively producing gas reservoir. This differs from an abandoned gas reservoir scenario in which the gas field is no longer producing.

Enhanced Oil Recovery Conversion. Under certain reservoir and fluid conditions, CO_2 can be injected into an oil reservoir in a process called miscible CO_2 enhanced oil recovery. The effect of the CO_2 is to mobilize the oil so that it can move more readily to the production wells. As the oil is produced, part of the injected CO_2 is produced with the oil. This CO_2 is then separated and re-injected. The EOR portion of U.S. CO_2 storage capacity represents the amount of CO_2 that could be permanently sequestered in association with EOR operations that have been converted from enhanced production to permanent storage.

In the U.S. most CO_2 EOR projects are located in the Permian Basin of West Texas, where projects have been in place for several decades. The source of most of the CO_2 is natural CO_2 from several fields in Colorado and New Mexico.[11] Some of the injected CO_2 is from gas processing or other sources. The current volume of CO_2 injected for CO_2 EOR is about 2.2 billion standard cubic feet per day.

In 2005, CO_2 EOR operations produced approximately 237,000 barrels of oil per day in the U.S. About 180,000 barrels per day of that occurred in West Texas, with most of the rest produced in the Rockies, Mid-Continent, and Gulf Coast.[12]

At the Weyburn Field in Saskatchewan, CO_2 from the Dakota Gasification Facility in North Dakota is injected into an oil reservoir for EOR and monitoring of CO_2 storage. Over the 25 year life of this project, it is expected that about 18 million tons of CO_2 will be sequestered.

Enhanced Coalbed Methane Recovery. CO_2 potentially can be sequestered in coalbed formations through the process of adsorption. CO_2 injected as a gas into a coalbed will adsorb onto the molecular structure and be sequestered. Methane is naturally adsorbed onto coalbeds and coalbed methane now represents a significant percentage of U.S. natural gas production. Major coalbed methane

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[11] *The Economics of CO_2 Storage*, Gemma Heddle, Howard Herzog, and Michael Klett, Laboratory for Energy and the Environment, Massachusetts Institute of Technology, August, 2003.
[12] Oil and Gas Journal, April 17, 2006.

production areas include the San Juan Basin of north-western New Mexico and south-western Colorado, the Powder River Basin of eastern Wyoming, and the Warrior Basin in Alabama.

The concept of enhanced coalbed methane recovery is based upon the fact that coalbeds have a greater affinity for CO_2 than methane. Thus, when CO_2 is injected into the seam, methane is liberated and the CO_2 is retained. This additional methane represents enhanced natural gas recovery. Depending upon depth and other factors, coalbeds may be mineable or unmineable. Because the process of mining the coal would release any stored CO_2, only unmineable coalbeds are assessed as representing permanent CO_2 storage.[13] One of the potential drawbacks to CO_2 injection into coal seams is that as the CO_2 is absorbed into the coal, the coal can swell, thereby reducing permeability. This phenomenon can make certain coals technically unsuitable or increase the cost of injection.

Gas Shales. The potential to sequester CO_2 in organic shale formations is based upon the same concept as that of coalbeds. CO_2 will adsorb onto the organic material, displacing methane. Gas shales have recently emerged as a major current and future source of natural gas production in the U.S. These include the Barnett Shale in the Fort Worth Basin, the Fayetteville and Woodford Shales in the Arkoma Basin, and the Appalachian Devonian Shale. These Devonian and Mississippian age organic shale formations represent tremendously large volumes of rock. To date little research has been done on enhanced gas recovery with organic shales. However, should it prove technically feasible, the U.S. could become one of the major areas worldwide for this type of storage.

Basalt. Basalt flows such as those of the Columbia River Basalts in the Pacific West, are believed to have the potential for permanent CO_2 storage. The storage process involves geochemical trapping, in which the CO_2 reacts with silicates in the basalt to form carbonate minerals.[14] While research is being carried out on basalt, it is considered unlikely that any commercial scale sequestration will occur in the foreseeable future due to the unconventional geology and likely difficulty in monitoring.

ICF has reviewed the DOE assessment information as published in the NATCARB Atlas and performed an independent assessment of the Lower-48 storage potential by state and reservoir type. This assessment allows analysis of the volumes of CO_2 that can be

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[13] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss,* Interstate Oil and Gas Compact Commission, January, 2005.

[14] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

stored regionally and the characteristics of this storage potential. We evaluated the distribution of storage potential by geologic category, location, and depth interval. In addition, we developed a model to assess the economics of sequestration in the U.S. also by state and reservoir type. The summary results are shown in **Table 2-7**. This table compares ICF's independent assessment with NATCARB and estimates by Battelle and the International Energy Agency (IEA).[15] [16]

ICF's estimate of the Lower-48 potential for storage is 3,375 Gt, which is higher than that of the 2007 NATCARB Atlas, and slightly less than that of the 2008 atlas. There are several reasons for the higher assessment. ICF included a rough estimation of the Gulf of Mexico potential, as well as an estimation of shale storage potential. In addition, ICF has an independent estimate of depleted oil and gas field potential, based upon a methodology of looking at the distribution of historical oil and gas recovery by region, and using this information to estimate CO_2 potential in areas not covered in the DOE study.

Table 2-8 presents the state level assessment by geologic category. Storage capacity associated with depleted oil and gas fields occurs where there has been significant natural gas and oil production, including Appalachia, the Gulf Coast, Mid-Continent, and Rockies. Saline reservoir potential occurs in many areas of the country. Coalbed methane potential is concentrated in the large coalbed methane production areas such as New Mexico and Wyoming, while shale gas potential is associated with some of the new gas shale basins that have emerged over the past decade.

<u>Economic Analysis of U.S. Storage Costs by Resource Type</u>

The ICF GeoCAT model is a spreadsheet model developed to calculate geologic storage costs for the entire inventory of U.S. geologic storage potential. This model was originally developed for DOE and is now being used by EPA to evaluate the overall characteristics and economics of geologic storage.

Much of the data in the economic model is based on the NATCARB Atlas database of storage potential that has been developed by the DOE Regional Sequestration Partnerships. [17] We have supplemented this with other sources or our own estimates where reservoir categories were not included in NATCARB for a given state/basin. We also have enhanced the data set with estimated drilling depths and other parameters not covered in the DOE effort. To account for the uncertainty in the estimates we have created a high and low estimate of sequestration volumes.

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[15] Edmonds, J., 2006, "Macro and Micro Views of the Role for Carbon Dioxide Capture and Geologic Storage in Addressing Climate Change," Battelle Pacific Northwest National Laboratory, April 4, 2006 presentation.
[16] Electric Power Research Institute, 2005, "Building the Cost Curve for CO2 Storage: North American Sector," prepared for the International Energy Agency Greenhouse Gas Program, J. Gale, Principal Investigator, EPRI, Palo Alto, CA.
[17] *Carbon Sequestration Atlas of the United States and Canada*, U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, March, 2007.

Table 2-7 Comparison of 2007 ICF Assessment of US Sequestration Potential with Published Estimates

Lower 48 Only Category	**Aug 2007 ICF** **Gt CO2**	**ICF Lower-48** **%**	2008 NATCARB Low Gt CO2	2008 NATCARB High Gt CO2	2007 NATCARB Gt CO2	2006 NATCARB Gt CO2	2006 Batelle Gt CO2	2005 IEA Gt CO2
Depleted Oil and Gas Fields								
Depleted Oil Reservoirs with EOR Potential	**17**	**0.5%**				7	12	0 [1]
Depleted Conventional Oil Fields	**60**	**1.8%**				13	0 [1]	11
Depleted Gas Fields	**50**	**1.5%**				9	35	35
subtotal	**126**	**3.7%**	138	138	82	29	47	46
Coal and Coalbed Methane								
Enhanced CBM	**20**	**0.6%**				17	0 [1]	
Deep Unmineable Coal Seams	**32**	**0.9%**				11	30	60
subtotal	**52**	**1.5%**	157	178	86	28	30	60
Shale Formations	**107**	**3.2%**	0	0	0	45	0 [1]	0 [1]
Deep Saline Formations								
Onshore	**1,187**				1,907	6,595	2,730	2,730
Offshore	**1,803 [4]**				242 [3]	0 [1]	900	
subtotal	**2,990**	**88.6%**	3,297	12,618	2,149	6,595	3,630	2,730
Onshore Saline-Filled Basalt	**100**	**3.0%**			84	100	240	0
Lower-48 Total	**3,375**	**100.0%**	3,592	12,934	2,401	6,797	3,947	2,836
Alaska					84			
U.S.					2,485			

Notes:
1 No covereage in assessment.
2 Represents only a partial assessment of US.
3 Atlantic Offshore Only
4 GOM, Pacific and Atlantic Offshore

Table 2-8 ICF Assessment of US Sequestration Potential by State and Reservoir Type

Gtonnes		Oil and Conv Gas Pools				Coalbed						
State	MARKAL Region	EOR	Abnd Oil	Abnd Gas	SUM Total	ECBM Areas	Unminable coal	SUM Total	shale	deep saline aquifers	basalt	SUM Total
ALABAMA	Eastern Gulf Coast	0.066	0.141	0.497	0.704	0.309	0.600	0.909	0.000	5.5	0.000	7.153
ARIZONA	Southern Rockies	0.000	0.000	0.007	0.007	0.000	0.000	0.000	0.000	19.0	0.000	19.009
ARKANSAS	Midwest	0.081	0.533	0.402	1.016	0.000	0.100	0.100	5.000	22.9	0.000	28.986
ATLANTIC OFFSHORE	Southeast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	286.6	0.000	286.640
CA. ONSHORE	California	1.238	8.033	1.800	11.070	0.000	0.000	0.000	0.000	161.1	0.000	172.150
COLORADO	Southern Rockies	0.201	0.224	0.222	0.646	3.000	4.400	7.400	0.000	2.2	0.000	10.221
DELAWARE	Southeast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
FLORIDA	Southeast	0.136	0.198	0.000	0.334	0.000	0.000	0.000	0.000	71.5	0.000	71.854
GEORGIA	Southeast	0.000	0.000	0.000	0.000	0.000	0.200	0.200	0.000	6.7	0.000	6.920
IDAHO	Northern Rockies	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	33.300	33.300
ILLINOIS	Midwest	0.172	1.086	0.003	1.260	2.880	0.000	2.880	0.000	50.4	0.000	54.540
INDIANA	Midwest	0.019	0.010	0.000	0.029	0.360	0.000	0.360	0.000	28.0	0.000	28.379
IOWA	Northern Midcon.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
KANSAS	Northern Midcon.	0.408	1.874	2.056	4.338	0.000	0.000	0.000	0.000	6.0	0.000	10.308
KENTUCKY	Midwest	0.009	0.260	0.390	0.659	0.360	0.020	0.380	28.000	7.5	0.000	36.549
LA. OFFSHORE	Gulf of Mexico	1.463	4.878	6.603	12.943	0.000	0.000	0.000	0.000	500.0	0.000	512.943
LA ONSHORE	Midwest	1.355	4.004	6.349	11.708	0.000	1.200	1.200	0.000	148.3	0.000	161.248
MARYLAND	Southeast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.0	0.000	0.009
MICHIGAN	Midwest	0.082	0.025	0.025	0.132	0.000	0.000	0.000	4.200	54.2	0.000	58.482
MINNESOTA	Midwest	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
MISSISSIPPI	Midwest	0.135	0.720	0.386	1.241	0.000	0.600	0.600	0.000	86.9	0.000	88.721
MISSOURI	Eastern Gulf Coast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
MONTANA	Northern Rockies	0.251	3.946	0.178	4.374	0.000	0.896	0.896	0.000	251.6	0.000	256.910
N. DAKOTA	Midwest	0.317	3.873	0.026	4.216	0.000	0.173	0.173	0.000	14.3	0.000	18.728
NEW MEXICO	Southern Rockies	0.904	2.956	5.489	9.349	11.000	0.000	11.000	0.000	5.5	0.000	25.886
NEBRASKA	Southern Rockies	0.018	0.151	0.009	0.178	0.000	0.000	0.000	0.000	2.8	0.000	2.968
NEVADA	Southern Rockies	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9.5	0.000	9.480
NEW ENGLAND STS	Eastern Gulf Coast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
NEW JERSEY	Midwest	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
NEW YORK	Eastern Gulf Coast	0.000	0.069	0.070	0.139	0.000	0.000	0.000	0.000	0.0	0.000	0.139
N. CAROLINA	Southeast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
OHIO	Midwest	0.000	0.200	0.200	0.400	0.000	0.040	0.040	8.500	34.6	0.000	43.510
OKLAHOMA	Midwest	1.412	4.390	3.935	9.738	0.000	0.800	0.800	10.000	0.0	0.000	20.543
OREGON	Pac. Northwest	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	27.0	33.300	60.300
PACIFIC OFFSHORE	Midwest	0.000	1.249	0.037	1.286	0.000	0.000	0.000	0.000	100.0	0.000	101.286
PENNSYLVANIA	Midwest	0.000	0.280	0.520	0.800	0.000	0.080	0.080	12.000	9.0	0.000	21.870
S. DAKOTA	Eastern Gulf Coast	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	34.7	0.000	34.652
S. CAROLINA	Southeast	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	6.7	0.000	6.720
TENNESSEE	Midwest	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.2	0.000	3.220
TEXAS ONSHORE	Midwest	7.554	19.025	15.368	41.947	0.000	3.600	3.600	20.000	288.2	0.000	353.789
TX. OFFSHORE	Midwest	0.000	0.603	1.781	2.384	0.000	0.000	0.000	0.000	300.0	0.000	302.384
UTAH	Southern Rockies	0.284	0.120	0.268	0.672	1.220	0.000	1.220	0.000	0.3	0.000	2.177
VIRGINIA	Southeast	0.000	0.000	0.136	0.136	0.563	0.000	0.563	0.000	0.0	0.000	0.699
WASHINGTON	Midwest	0.000	0.000	0.000	0.000	0.000	2.300	2.300	0.000	26.0	33.300	61.600
WEST VIRGINIA	Southeast	0.000	0.030	0.570	0.600	0.000	0.110	0.110	19.000	6.4	0.000	26.090
WISCONSIN	Midwest	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0	0.000	0.000
WYOMING	Northern Rockies	0.421	0.657	2.327	3.405	0.000	16.814	16.814	0.000	414.0	0.000	434.193
LOWER 48 TOTAL	L48 Total	16.527	59.535	49.654	125.716	19.692	31.933	51.625	106.709	2,990.6	99.900	3,374.560
L48 OFFSHORE	L48 Offshore	1.463	6.730	8.421	16.614	0.000	0.000	0.000	0.000	1,186.640	0.000	1,203.254
L48 ONSHORE	L48 Onshore	15.064	52.805	41.233	109.102	19.692	31.933	51.625	106.709	1,804.0	99.900	2,171.306

The model evaluates the assessed inventory of geologic storage in the U.S., including all of the geologic categories discussed above. Currently, the basic unit of analysis is the assessed quantity of potential by state and geologic category. For example, the saline formations of Mississippi would be one analytic category. Each of these categories is assigned a typical drilling depth for costing.

The current model has many cost parameters including capital and operating costs for pumps, pipelines, injection wells and monitoring wells and equipment. These are typically functions of key engineering parameters such as depth, pressure and flow rate. Other cost elements are initial geological and geophysical (G&G), survey and regulatory costs for site selection, permitting and certification and recurring non-well monitoring during the project injection period and afterwards. There are also cost parameters for contingencies and for general and administrative costs (a.k.a. owner's costs). Payments to the landowner for surface disturbance and injection rights are included as are "insurance payments" to a government entity that is assumed to take over long-term liability for the site after its abandonment.

The main output of the model is the quantity of storage capacity (measured in tonnes) that is available at different price steps (measured in real U.S. dollars per tonne). These data can be aggregated by type of storage and by state in any desired groupings. The aggregate result of the economic analysis is shown in **Figure 2-6**. This is an aggregate cost curve for the geologic storage potential of the U.S. The chart shows that most of the storage potential is characterized by costs of less than $25 per tonne. A substantial volume of potential was evaluated to cost less than $10 per tonne. **Figure 2-7** shows results for saline reservoirs alone**.**

Figure 2-6 Summary of Economic Analysis of Total U.S. Sequestration Capacity

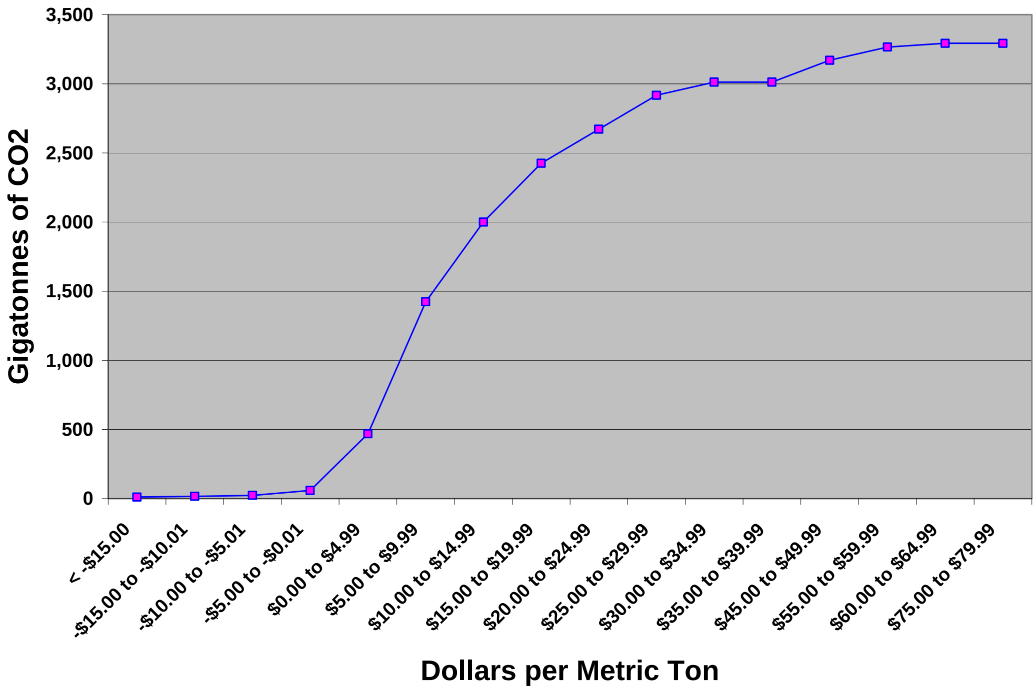
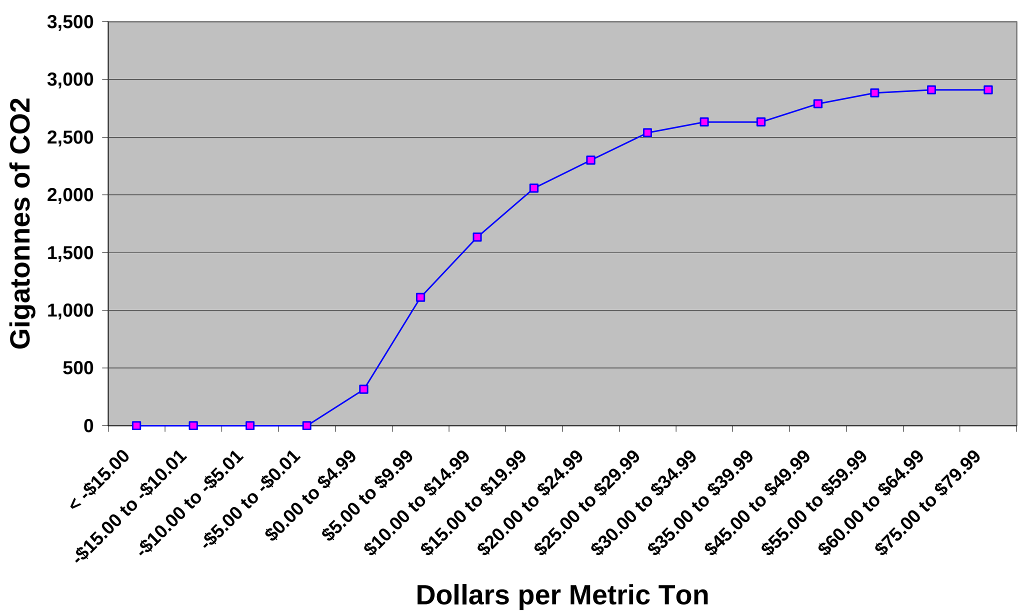


Figure 2-7 Summary of Economic Analysis of Saline Reservoir Potential in the United States



CO_2 Storage Potential of Western Canada

Canada has geologic storage potential in the Western Canadian Sedimentary Basin, as well as a small amount of potential in Eastern Canada. The great majority of potential is in the western provinces.

The Western Canadian Sedimentary Basin (WCSB) has geological characteristics that are amenable to the storage of very large volumes of CO_2. A portion of the potential – that associated with depleted oil and gas reservoirs --was assessed in a 2004 study by the Alberta Energy Research Institute.[18] The study encompassed the screening and evaluation of over 30,000 gas and oil reservoirs in Alberta, BC, Saskatchewan, and Manitoba. Reservoir volumes were evaluated and three categories of sequestration potential were assessed. "Practical Capacity" considers technical limitations, reservoir location, reservoir size, infrastructure, and economic factors. The study included only depleted conventional oil and gas reservoirs, and did not assess potential in aquifers, coalbeds, shale or other lithologies. The results are shown in the upper part of **Table 2-9.** A volume of 3,700 tonnes of practical capacity in oil and gas reservoirs was assessed for Western Canada.

The 2007 U.S. DOE NATCARB Atlas provided preliminary assessments of sequestration potential in Western Canada. [19] This study assessed 60,000 Mt of CO_2 sequestration potential in Viking Formation saline reservoirs. This is considered to represent only a fraction of the total WCSB saline reservoir potential, as it is just one formation. For comparison, the states of Montana and Wyoming have been assessed as having several hundred billion tonnes each of saline potential. It is therefore likely that the WCSB has potential of at least that magnitude.

The CANMET Energy Technology Center (part of Natural Resources Canada) has assessed the saline reservoir potential of Eastern Canada.[20] Two basins in the vicinity of Lake Huron and Lake Erie have a combined potential of 730 tonnes. This is considered to be only a partial assessment of Eastern Canada, as it includes conventional, shale, and coalbed lithologies in other areas. To our knowledge, no sequestration assessment of other onshore and offshore Eastern Canada basins has been published. A January 2008 presentation from Natural Resources Canada indicates the potential for 5,000 tonnes of coalbed capacity in Canada.[21]

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[18] Bachu, Stephan, 2004, "Evaluation of CO2 Sequestration Capacity in Oil and Gas Reservoirs in the Western Canadian Sedimentary Basin," Alberta Energy Research Institute, March, 2004.
[19] U.S. Department of Energy, 2007, "NATCARB Atlas", DOE NETL, Morgantown, WV.
[20] Shafeen, Ahmed, "CO2 Sequestration Opportunities for Ontario," CANMET Energy Technology Center, Ottawa.
[21] Reynen, Bill, 2008, "CO2 Storage Potential in Canada," Natural Resources Canada slide presentation, January 22, 2008.

In 2005, the Pacific Northwest National Laboratory (PNNL) developed an assessment and cost curves for geologic sequestration in the U.S. and Canada. The Canadian assessment totaled 1,300 gigatonnes of potential and the U.S. assessment was 4,000 gigatonnes. No breakdown of the assessment by reservoir type was apparently published, but the great majority was stated to be associated with saline reservoirs in the WCSB.[22]

Table 2-9 Canadian Geologic Sequestration Capacity

CO2 Sequestration Potential of Canada (incomplete assessments)
Mt = Million Tons of Capacity

1. Results of Bachu Western Canada Study

	All Reservoirs		Reservoirs With Practical Potential	
Category	Count	Mt CO2	Count	Mt CO2
Gas reservoirs	25,000	8,500	771	3,180
Oil reservoirs - primary depletion	8,400	450	98	522
Oil reservoirs - secondary or tertiary recovery	695	362		
	34,095	9,312	869	3,702

2. Combined Results of Bachu, NATCARB, etc.

Province	Depleted Oil and Gas (Practical) (Bachu, 2004) Mt CO2	Saline (NATCARB and CANMET) Mt CO2	Coal Reservoirs (NATCARB and NR Canada) Mt CO2	Total Mt CO2
Alberta	2,812	60,000	5,000	67,812
Northeast BC	810	not assessed	not assessed	810
Saskatchewan	79	not assessed	not assessed	79
Manitoba	1	not assessed	not assessed	1
Ontario	0	730	not assessed	730
Total	3,702	60,730	5,000	69,432

Sources:
1. Bachu, Stefan, 2004, "Evaluation of CO2 Sequestration Capacity in Oil and Gas Reservoirs in the Western Canadian Sedimentary Basin," Alberta Energy Research Institute, March, 2004.
2. DOE, 2007, NATCARB CO2 Sequestration Atlas, DOE NETL, Morgantown, WV, 2007.
3. Shafeen, Ahmed, CANMET Energy Technology Center, Ottawa, CA (for Ottawa Potential)
4. Reynen, Bill, 2008, "CO2 Storage Potential in Canada," Natural Resources Canada, Ottawa, Ont., January 2008.

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[22] Dooley, J.J. and R.T. Dahowski, 2006, "Carbon Dioxide Capture and Geologic Storage," *Global Energy Technology Strategy Program*, Battelle Memorial Institute, April, 2006.

Dooley, J.J., R.T.Dahowkski, C.L. Davidson, S. Bachu, N. Gupta, and J. Gale, 2004, "A CO2 Storage Supply Curve for North America and its Implications for the Deployment of Carbon Dioxide Capture and Storage Systems," Battelle/Pacific Northwest National Laboratory, in E.S. Rubin, D.W. Keith and C.F. Golboy (eds.) *Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies*, U.K., 2004.

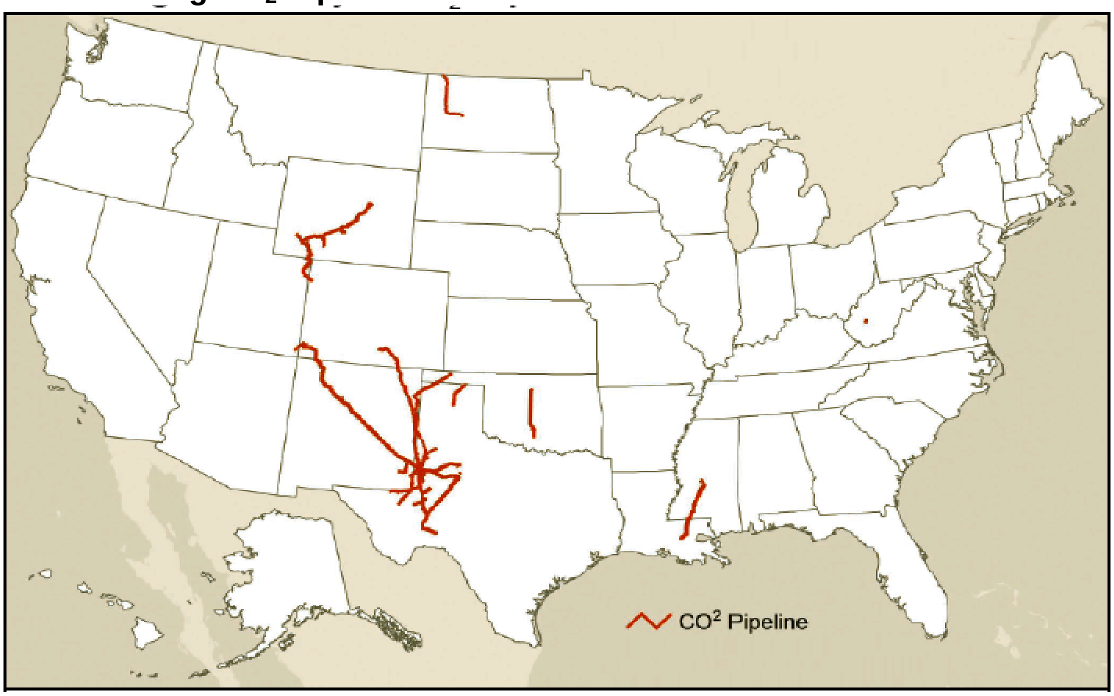
Dooley, J.J., and S. J. Friedman, "A Global by Regionally Disaggregated Accounting for CO2 Storage Capacity: Data and Assumptions for Compiling Regional CO_2 Storage Capacity Supply Curves for Incorporation within Objects/Minicam," Lawrence Livermore National Laboratory Paper UCRL-SR-209663, February 14, 2005.

2.5 CO_2 Transportation

CO_2 pipelines are a mature technology and are the most common method for transporting large CO_2 volumes. Gaseous CO_2 is typically compressed to a pressure near 2,200 psi (15.2 MPa) in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it possible to pump it as a liquid and thereby easier and less costly to transport. CO_2 also can be transported as a liquid in ships, tank trucks, or rail tankers that carry chilled CO_2 in insulated tanks.

The first long-distance CO_2 pipeline came into operation in the early 1970s in the Permian Basin of West Texas. Today in the United States, over 5,800 km (~3,600 miles) of pipeline transports more than 40 million tonnes of CO_2 per year from natural and anthropogenic sources. (**Figure 2-8**) These pipelines operate in the liquid and supercritical CO_2 phases at ambient temperatures and high pressure. In most of these pipelines, there are intermediate (booster) pumping stations to compensate for pressure drop along the pipeline.

Figure 2-8 Existing CO_2 Pipelines



Source: U.S. Dept. of Transportation, National Pipeline Mapping System, For official use only. (June 2005). [https://www.npms.phmsa.dot.gov]

The design of a CO_2 pipeline is similar to that of a natural gas pipeline except that higher pressures must be accommodated; often with thicker pipe (see **Table 2-10**). The added thickness requires more steel in the line pipe, adds transportation costs to move the line pipe to the construction site and adds to the cost of welding the line pipe. CO_2 pipelines also differ in that they require CO_2-resistant elastomers around valves and other fittings and their construction includes fracture arrestors every 1,000 feet to reduce fracture propagation, which is more likely in CO_2 pipelines due to their slower decompression characteristics.

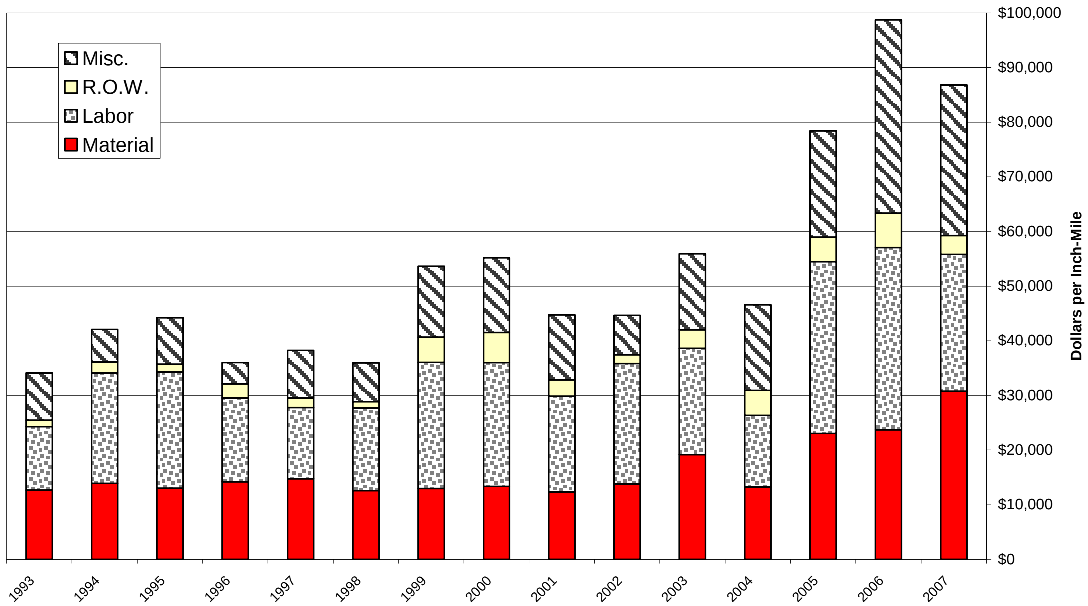
Table 2-10 CO_2 and Natural Gas Designs and Steel Requirements

								Steel Cost			
	Outside Diameter	Max Stress	Class Coeff.	Max Pressure	Final Thickness	Inside Diameter	Tons per Mile	$/mile cost @500/Ton	$/mile cost @900/Ton	$/inch-mile cost @500/Ton	$/inch-mile cost @900/Ton
Natural Gas	12.75	70,000	0.6	1,000	0.375	12.00	130	65,238	117,428	5,117	9,210
Natural Gas	16	70,000	0.6	1,000	0.375	15.25	165	82,371	148,268	5,148	9,267
Natural Gas	24	70,000	0.6	1,000	0.500	23.00	330	165,182	297,327	6,883	12,389
Natural Gas	30	70,000	0.6	1,000	0.625	28.75	516	258,096	464,573	8,603	15,486
Natural Gas	36	70,000	0.6	1,000	0.750	34.50	743	371,658	668,985	10,324	18,583
Natural Gas	42	70,000	0.6	1,000	0.875	40.25	1,012	505,868	910,563	12,044	21,680
Carbon Dioxide	12.75	70,000	0.6	2,200	0.375	12.00	130	65,238	117,428	5,117	9,210
Carbon Dioxide	16	70,000	0.6	2,200	0.419	15.16	184	91,787	165,217	5,737	10,326
Carbon Dioxide	24	70,000	0.6	2,200	0.629	22.74	413	206,521	371,737	8,605	15,489
Carbon Dioxide	30	70,000	0.6	2,200	0.786	28.43	645	322,688	580,839	10,756	19,361
Carbon Dioxide	36	70,000	0.6	2,200	0.943	34.11	929	464,671	836,409	12,908	23,234
Carbon Dioxide	42	70,000	0.6	2,200	1.100	39.80	1,265	632,469	1,138,445	15,059	27,106

Another important difference between a CO_2 pipeline and a natural gas pipeline is that the CO_2 pipeline is moving a supercritical fluid that is pumped – not compressed at booster stations. This is typically done with electric powered centrifugal pumps. Inlet pressures at the pumps would be about 1,850 psi (12.8 MPa) and outlet pressures 2,200 psi (15.2 MPa).

The costs of building pipelines in the U.S. and Canada have gone up significantly in the last several years (**Figure 2-9**) due to higher material and labor costs. In 2006 and 2007, the cost or large diameter gas pipelines have been over $80,000 per mile per inch diameter of pipe. This is the construction cost of the pipeline itself and does not include the cost of compressors stations. Costs can vary significantly from location to location based on the terrain, the density of development along the pipeline route and local construction costs.

Figure 2-9 Historical Gas Pipeline Costs by Component



Average of large-diameter gas pipelines 30 to 36 inches FERC data compiled by Oil & Gas Journal

Representative transportation costs for CO_2 by new pipeline are shown in **Table 2-11**. Since there are large economies of scale for pipeline, CO_2 transportation costs would depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. The longer the distance from the source to the CO_2 sink, the more chance there is for other sources to share in the transportation costs. The hypothetical example at the bottom of **Table 2-11** shows what costs might look like for a distance of 150 miles between source and sink, with the pipeline diameter growing with distance as more sources are fed into the same system. This example comes to $4.61 per tonne of CO_2 for 150 overall miles pipeline distance traveled.

Table 2-11 CO_2 Pipeline Cost Examples

CARBON DIOXIDE PIPELINES								
Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Total Cost of Service in $/metric ton per 75 miles or 121 km	Flow Capacity in metric tons/day	Flow Capacity in million standard cubic feet per day (60 degrees F and 14.73 psi)		Number of 500 MW IGCC plants accomodated
12.75	12.0	0.39	$ 75,000	$4.36	10,775	203		0.97
16	15.0	0.49	$ 78,116	$3.25	19,139	361		1.73
24	22.5	0.73	$ 84,119	$2.02	53,385	1,007		4.83
30	28.2	0.92	$ 86,399	$1.56	93,887	1,771		8.49
36	33.8	1.10	$ 88,678	$1.27	148,913	2,808		13.46
42	39.4	1.28	$ 90,958	$1.10	219,942	4,148		19.88

Note: 500 MW IGCC plant would produce 512 metric tonnes of CO2 per hour. Of this, 90% or 461 tonnes would be captured. Maximum CO2 tranport needs would be 11,064 tonnes per power plant per day. Cost of service based on 7 cents per kWh electricity.

Example Spacial Assumptions	Miles	$/Mile per Tonne	Cost per Tonne	Annual Cost per Power Plant @85 Utilization Rate
Single Power Plant Pipeline (12 inch, small gathering) distance in miles	**25**	$0.058	$1.45	$4,986,315
Two Power Plant Pipeline (16 inch, large gathering) distance in miles	**25**	$0.043	$1.08	$3,717,212
Eight Power Plant Pipeline (30 inch, mainline) distance in miles	**100**	$0.021	$2.07	$7,117,235
Total Distance & Costs	**150**	**$0.031**	**$4.61**	**$15,820,762**

Restrictions on Chemical Composition for CO_2 Pipelines
.
CO_2 pipelines, like natural gas pipelines, operate with restrictions on the chemical composition of fluids that can be moved through them. **Table 2-12** shows the typical quality specifications for U.S. CO_2 pipelines and the concerns that lead to the restrictions. The most important limit is the maximum amount of water permitted into the pipeline. An excessive amount of water would produce carbolic acid that would corrode standard carbon steel. It is much cheaper to take the water out of the transported fluids than it is to build the pipeline with corrosive resistant steel or liners.

Since all the operating U.S. pipelines are now used for EOR, there are limits placed on constituents to ensure that the transported fluid's minimum miscible pressure in crude oil will not be so high as to restrict its use for EOR. This includes minimum requirements for CO_2 and maximum limits on nitrogen and hydrocarbons. A pipeline that was built to transport CO_2 for disposal in saline reservoirs would not need to have these same limits.

Hydrogen sulfide is found in some natural gases (frequently along with CO_2) and is removed at gas processing plants. The very first CO_2 floods in the Permian Basin used CO_2 gas (often containing some H_2S) that was produced at nearby gas processing plants. Since H_2S mixes easily with crude oil, its presence in the CO_2 improved its use for EOR. The pipeline systems used for those initial projects had a high H_2S quality limits. The more recently built CO_2 pipelines, however, limit H_2S to around 10 ppm, since H_2S is a health hazard that would make it more difficult to permit the pipelines.

Table 2-12 US CO_2 Pipeline Quality Specifications

Constituent	Type of Limit	Value of Limit	Reason for Concern
CO_2	Minimum	95%	Minimum miscible pressure for EOR
Nitrogen	Maximum	4%	Minimum miscible pressure for EOR
Hydrocarbons	Maximum	5%	Minimum miscible pressure for EOR
Water	Maximum	30 lbs/MMcf	Corrosion
Oxygen	Maximum	10 ppm	Corrosion
H_2S	Maximum	10-200 ppm	Safety
Glycol	Maximum	0.3 gal/MMcf	Operations
Temperature	Maximum	120 deg F	Materials

2.6 Existing and Planned CCS Projects

Table 2-13 is a listing of existing CCS projects and some of the projects that have been proposed. Although natural gas processing is the source of CO_2 for most of the existing CCS projects, coal power plants dominate the proposed projects. Among the 31 worldwide proposed coal power plant CCS projects, 16 are for IGCCs with pre-combustion capture, 11 for pulverized coal with post-combustion capture, four are oxy-fired coal.

Table 2-13 Major Carbon Capture & Storage Projects

Owner/Operator	Location	Type
	Existing	
Blue Source Multiple	Wyoming, Colo.	NG processing
Dakota Gasification	N. Dakota	Syngas manufacturer
Salah Gas Salah	Algeria	NG processing
Statoil Sleipner	Norway (offshore)	NG processing
Gas de France K12-B	Netherlands (offshore)	NG processing
Alcoa Kwinana	Australia	Aluminum plant
	Proposed	
AEP	Oklahoma	PC power
AEP	W. 'Virginia	IGCC coal power
AEP	Ohio	IGCC coal power
Basin Electric	Beulah N.D.	PC power (retrofit)
Clean Energy Systems	Bakersfield Calif.	Oxyfuel gas power
Duke Energy Edwardsport	Indiana	IGCC coal power
Duke Energy Cliffside	NC	PC power
Excelsior Energy	Mesaba Minn.	IGCC coal power
H Energy (BP & Rio Tinto) Carson	Calif.	IGCC pet coke power
Jamestown Bd Public Utilities	Jamestown NY	CFB oxyfuel coal power
NRG Sugar Land	Texas	PC power (retrofit)
NRG Tonawanda	NY	IGCC coal power
Peabody Energy	TBA in USA	Syngas production
Peabody Energy	Southern Illinois	SCPC
Seminole Electric Coop. Tampa	Florida	SCPC
Tenaska Sweetwater	Texas	SCPC power
Tenaska Taylorsville	Illinois	IGCC coal power
Xcel	Colorado	IGCC coal power
EPCOR	Alberta Canada	IGCC coal power
SaskPower	Saskatchewan Canada	Not announced
Spectra	British Columbia	NG processing
Callide Queensland	Australia	Oxyfuel coal power
Centrica Teesside	UK	IGCC coal power
E.ON Killingholme	UK	IGCC coal power
E.ON Kingsnorth	UK	SCPC power
Fund. Ciuden de la Energia El Bierzo	Spain	Oxyfuel Coal Power
Gorgon	Australia	NG processing
GreenGen Tianjin	China	IGCC coal power
Hydrogen Energy Kwinana	Australia	IGCC coal power
Hypogen (EC Project)	Norway, UK, Germany	Coal/NG offshore CCS
Monash Energy	Latrobe Valley Australia	IGCC coal liq/power
Norwegian Ministry of Karsto	Norway	NG processing
Petroleum and Energy	Mongstad Norway	NGCC CHP
Powerfuel Yorkshire	UK	IGCC coal power
RWE Tilbury	UK	SCPC
RWE Blyth	UK	SCPC
RWE	Germany	SCPC
StatoilHydro	Barents Sea	NG processing
Vattenfall Schwarze Pump	Germany	Oxyfuel coal power
ZeroGen Brisbane	Australia	IGCC coal power

NG = natural gas; SCPC = supercritical pulverized coal, NGCC = natural gas combined cycle, PC = pulverized coal, IGCC = integrated gasification combined cycle, CHP = combined heat & power
Source: Climate Change Business Jounal, May 2008 and press reports

3. Implications of Carbon Reduction Policies on Demand for CCS

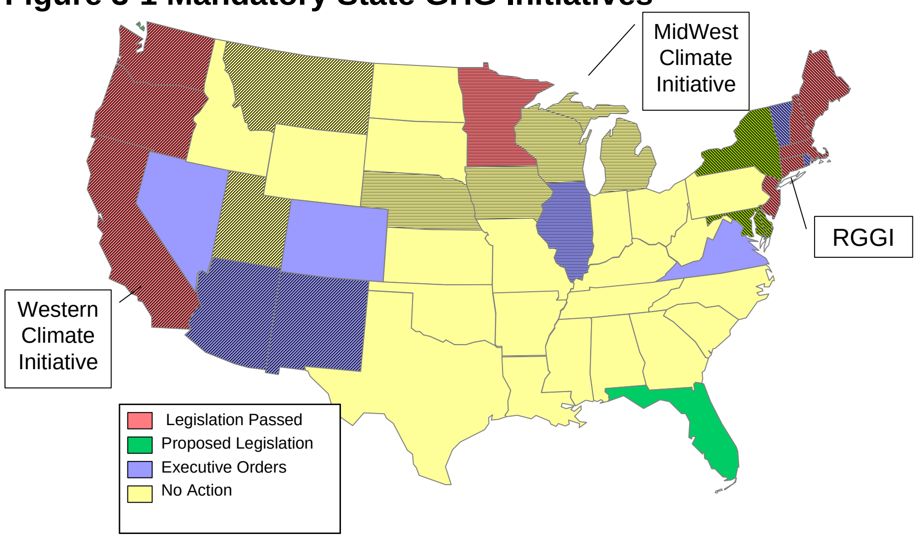
3.1 Regulatory Overview

The U.S. Congress is considering several possible mandatory greenhouse gas (GHG) emission control regulations for the U.S. Also, several states, individually and as groups, are proceeding with their own programs. In Canada, several provinces have announced GHG control programs and the federal government is proceeding with a nationwide regulatory effort.

U.S. Policies

Figure 3-1 shows the status of current state actions in the U.S. as of January 2009. For example, the Regional Greenhouse Gas Initiative (incorporating ten New England and Mid Atlantic states) has targeted a 2009 start date for participating states to impose a cap-and-trade regime and a market based emission trading system to reduce CO_2 emissions from power plants greater than 25 Megawatts (MW). California has passed Assembly Bill 32 with the aim of reducing GHG emissions to their 1990 levels by 2020. Many of the western states have joined with California into the Western Climate Initiative to coordinate actions. The Midwest Climate Initiative serves the same purpose for states in the region. Additionally, a total of 31 states participate in the Climate Registry, two have independent voluntary registries, and four participate in independent mandatory reporting.

Figure 3-1 Mandatory State GHG Initiatives



On the federal level, several members of Congress have put forward proposals to reduce emissions either in specific sectors or on an economy wide basis. Currently there are well over a dozen different proposals on control of greenhouse gases being considered by the U.S. Congress, ranging from specific bills to proposal drafts that have not yet been submitted as formal bills. Some of the key aspects of the proposals include the following:

- Most take a multi-sector approach and regulate many or all segments of economy. In other cases, the bills target the power sector (or power plus vehicles), as a starting point to possible further future regulation.

- In accordance with the IPCC findings that substantial reductions in emissions will be needed to reduce the chance of adverse climatic effects, the most recent proposals target a 60 percent to 80 percent reduction in U.S. CO_2 emissions by 2050. (**Figure 3-2**)

- The proposals take a market-based approach using a carbon tax or cap-and-trade program to limit emissions rather than mandating specific technologies. The market-based approach is intended to provide economic signals that allow entities to choose economically efficient compliance options.

- The proposals for cap and trade systems sometimes include some allocation of free allowances to regulated entities, particularly in the early years of the programs. The allowances that are not allocated are auctioned with the proceeds going toward tax reductions, R&D and other purposes.

- International offsets (certified CO_2 reductions in foreign counties) and domestic offsets (certified reductions in the U.S. from agricultural, forestry and other entities not included under the cap and trade system) are allowed to some degree in cap and trade proposals. However, many proposals limit the fraction of offsets that can be used so as to encourage emission reductions within the U.S. through the application of new technology within the power and industrial sectors.

- Many bills try to further encourage the development and application of new technologies such as CCS by funding R&D programs and providing financial incentives through a technology fund or the issuance of “bonus allowances”

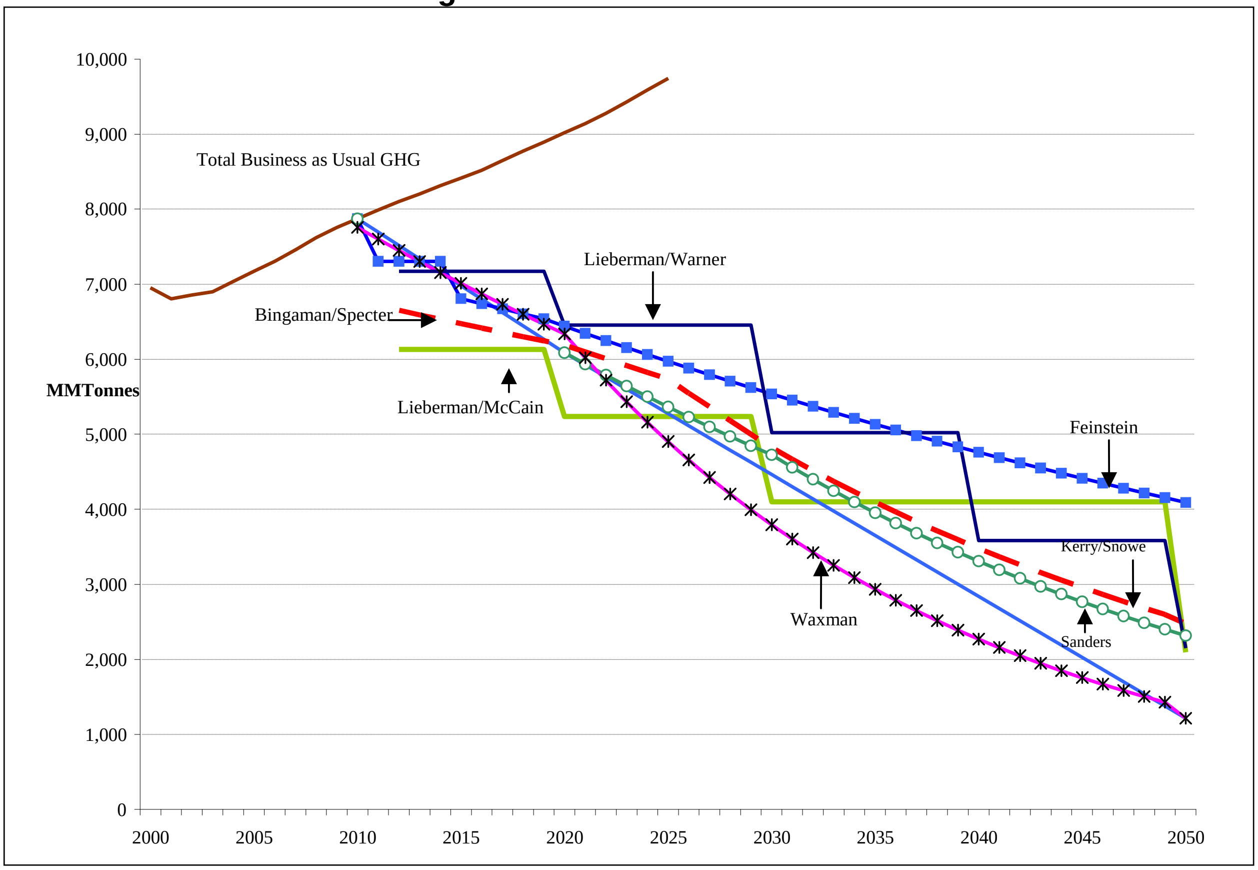
- As cost containment measures, some cap-and-trade bills set a maximum price level or “safety valve” that allowance prices cannot exceed. In other cases the proposals call for an independent board to monitor the GHG allowance market and take actions (such as issuing additional allowances or borrowing allowances from future year allotments) when prices are high and might unacceptably damage the economy. Such a board is intended to operate in manner similar to how the Federal Reserve Board monitors and regulates financial markets.

- The bills differ on what the point of regulation – upstream or downstream – would be and what entities might be covered or exempted in terms of size.

- Because of the potential adverse impacts on the international competitiveness of energy intensive U.S. industries, some proposals set out requirements that imported commodities or products obtain allowances to account for the CO_2 emitted in their production in a foreign country.

- Many proposals allow the use of GHG allowance from other GHG control programs such as that of the EU and call for the U.S. to actively encourage other countries such as China and India to develop mandatory GHG control programs.

Figure 3-2 GHG Emission Targets Under Several Economy Wide Bills under Consideration in the US Congress



Source: ICF estimates based on proposals.

As will be discussed more fully in the next chapter the key features of any future U.S. GHG legislation that will affect the timing and level of CCS in the U.S. will be:

- The level of control mandated: The sooner and deeper the cuts in CO_2 emissions are required, the higher will be the allowance prices and the financial incentives for CCS.

- Permitted use of offsets: To the extent that large numbers of offsets are permitted, there will be less pressure on reducing domestic power plant and industrial emissions through CCS and other means.

- Incentives for CCS: CCS will be boosted by the allocation of “bonus allowances” and other financial incentives.

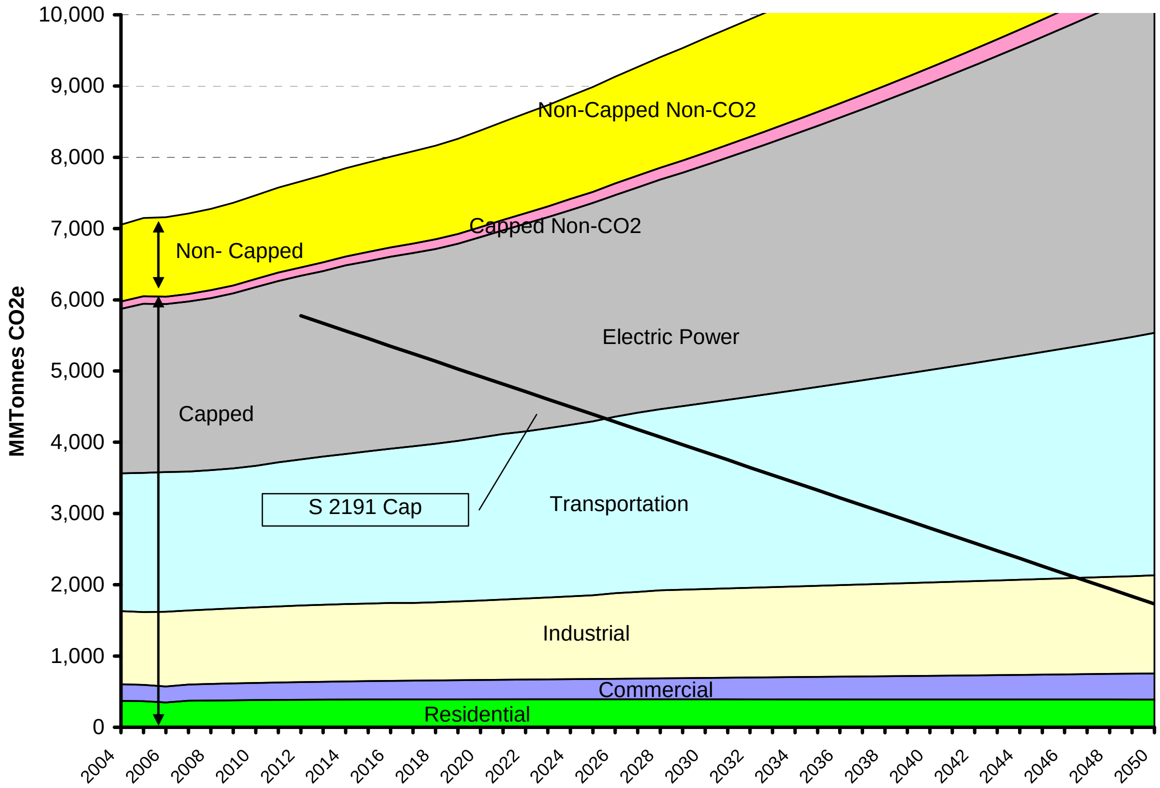
- Incentives for other compliance options: Large incentives for energy conservation, renewables and nuclear power may make CCS look less attractive in some instances.

- Moderate Safety Valve Prices: If safety valve prices are set low, adequate incentives for CCS may be delayed.

- Regulatory regime for CCS: There are certain regulatory issues related to CCS, most importantly the long-term liability for storage sites, that probably will have to be determined by legislation before CCS is applied on a large-scale in the U.S. The liability issue is not a part of existing GHG proposals (except as a request for study of the issue) but might be included in future GHG legislation.

The role that CCS could play in meeting U.S. GHG goals can be illustrated by **Figure 3-3** which shows the emission limits of the Lieberman/Warner/Boxer bill overlaid onto projected CO_2 emission levels.

Figure 3-3 Lieberman/Warner/Boxer GHG Cap Relative to Projected Emissions



Source: Projected emissions are from EIA AEO.

Based on the relative economics of GHG abatement options, most analysts believe the initial reductions will come mostly from reductions in non-CO_2 gases in industrial processes, conservation in all sectors, international and domestic offsets and changes in the methods of generating power. Because of the limited potential in the first three categories (including a legislative restriction on the use of offsets) the Lieberman/Warner/Boxer targets would lead to largely decarbonizing the power sector sometime after the year 2030. Unless new nuclear power plants were to be constructed on a massive scale and replace older fossil plants, most analysts believe the target will require a large amount of CCS to capture emissions from U.S. fossil-fuel power plants.

Canadian Policies

Although Canada remains a signatory to the Kyoto Protocol, it has indicated that it cannot meet its Kyoto target of 6 percent below 1990 GHG emission levels by 2010. Canada's annual GHG emissions are currently more than 25 percent higher than they were in 1992 and 32 percent higher than Canada's Kyoto Protocol targets. This growth is due in part to the continued expansion of Canada's production and expert of oil and gas. Without immediate action, Canada's emissions from all sectors could increase by another 26% to reach 940 million tonnes by 2020.

The federal government has committed to reducing Canada's total emissions, relative to 2006 levels, by 20% by 2020, and by 60-70% by 2050. The level of effort required to achieve this reduction goal will be significant, as Canada has a growing population, a growing economy and increasing energy exports.

In April, 2007, the Government of Canada released its *Regulatory Framework for Air Emissions*, which outlines both greenhouse gas (GHG) and air pollutant reduction targets. Rather than aiming to reduce absolute emissions, Canada's GHG regulations will require regulated facilities to reduce their intensity of emissions (emissions per unit of production), beginning in 2010. Nine affected industrial sectors include electricity generation produced by combustion and oil and gas (including upstream oil and gas, downstream petroleum, oil sands, and natural gas pipelines).

<u>Covered Industrial Sectors:</u>
Electricity generation; oil and gas (including oil sands, upstream oil and gas); natural gas pipelines; petroleum refining; pulp and paper; iron and steel; smelting and refining; cement, lime, potash; and chemicals and fertilizers.

Canada's federal GHG regulatory program will be based on an emissions intensity baseline target for entities or sectors, depending on the industrial sector. Covered entities whose actual emissions intensity (in a given year) is below their 2006 target will receive tradable credits equal to the difference between their target emission intensity and their actual emission intensity, multiplied by their production in that year. The proposed framework allows for banking of credits to be used in future compliance periods, or sold to other parties through inter-firm trading.[23]

In March 2008, the Government of Canada published *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions.*[24] This document, which strengthens and elaborates on the originally announced April 2007 framework, presents final policy decisions on emissions targets, compliance mechanisms, and Canada's eventual transition to fixed emissions cap from the intensity-based system. In particular, the latest document, produced through consultations with sixteen Canadian industrial sectors, presents carbon CCS as a key tool in meeting the 2020 national climate target.

The results of analyses performed by Natural Resources Canada of the proposal are shown in **Table 3-1** for the main industries covered by the federal program. Actual reductions of 125 million tonnes are expected from CCS and other means by 2020.

[23] Environment Canada, 2007.
[24] Environment Canada, 2008

Table 3-1 Natural Resources Canada's Projected Canadian GHG Emissions and Reductions in 2020

Covered Industrial Sectors	2006 Covered Emissions		2020 Projected Emissions		2020 Emissions Post-regulations	
	Mt CO_2e	%	Mt CO_2e	%	Mt CO_2e	%
TOTAL	**356**	**100%**	**427**	**100%**	**299**	**100%**
Oil Sands	29	8%	108	25%	49	17%
Electricity	123	35%	122	29%	89	30%
Petroleum Refining	23	7%	32	8%	20	7%
Chemicals	9	2%	12	3%	8	3%
Fertilizers	8	2%	9	2%	7	2%
Upstream Oil & Gas	94	26%	68	16%	57	19%
Natural Gas Pipelines	15	4%	14	3%	13	4%
Potash	1	0%	1	0%	1	0%
Iron Ore Pelletizing	2	1%	4	1%	3	1%
Lime	3	1%	4	1%	3	1%
Iron, Steel & Titanium	13	4%	19	5%	18	6%
Pulp & Paper	7	2%	5	1%	4	1%
Aluminium & Alumina	13	4%	13	3%	11	4%
Cement	13	4%	14	3%	13	4%
Base Metal Smelting	4	1%	3	1%	3	1%
Total reductions from projected emissions by 2020					**125 Mt (29%)**	

Under the regulatory framework, GHG emissions intensity reductions will be based on a 2006 baseline year. For existing facilities, the framework establishes a stringent, short-term mandatory reduction target based on emission intensity with an 18 percent improvement over 2006 baseline levels required by 2010. Subsequent emission-intensity reductions for existing facilities will be 2 percent per year to 2015. The 18 percent emissions-intensity reduction only applies to combustion and non-fixed process emissions, and pre-defined fixed process emissions will not have a reduction target to meet.

More detailed target-related information was published in *Turning the Corner* in March, which covered: target application; minimum thresholds; definition of new facility; application of a cleaner fuel standard; and carbon capture and storage. Here, the Government has identified three approaches to GHG target application throughout the regulated sector:

- Facility-Specific: Each facility within a sector receives an individual target of an 18 percent reduction from its own 2006 emission intensity. Applies to most sectors, including Oil Sands and Upstream Oil & Gas.
- Sector-Wide: All facilities within a sector face the same target – an 18 percent reduction from the sector's average 2006 emission intensity. Applies to Lime, Pulp & Paper, Alumina and Cement.
- Corporate-Specific: Each company within a sector receives a target of an 18 percent reduction from the average 2006 emission intensity of its entire fleet of facilities. Applied to Electricity sector only.

Other Canadian regulatory highlights are presented below.

Target for New Facilities

Under the framework, new facilities are defined as those whose first year of operation is 2004 or later. Along with a 2 percent annual improvement through 2020, new facilities will be subject to a clean fuel standard (CFS), which is intended to provide incentives for the adoption of best available technologies at the outset of operation. A three-year grace period will be provided to such facilities, before targets apply in the fourth year of operation (even if fourth year is prior to 2010). For facilities that are "built capture ready", CFS will not apply until 2018. For the electricity sector, fuel-specific clean fuel standards will be based on the equivalent of: natural gas combined cycle; oil fired gas turbine; and supercritical (coal).

In light of the above, new Canadian oil sands upgraders and in-situ plants, as well as coal-fired electricity, that begin operating in 2012 or after must meet a stringent target based on the use of carbon capture and storage (CCS) by 2018. From 2012, new coal-fired units must meet a CCS standard, starting in 2018. Such facilities will also require 2 percent annual improvement from CFS, following a three-year grace period; however, for facilities that are "built capture ready", CFS does not apply. By 2018, the CCS standard for these facilities will be applied.

The CCS standard represents an emission performance standard based on CCS; therefore, any technology that meets this standard will be considered acceptable toward meeting compliance. According to the government, the reduction of emissions, and therefore the target, is a function of: 1) the fraction of emissions at a capture-ready facility that are technically and/or economically capturable; and 2) the efficiency of the capture equipment. Several leading studies have indicated that capture rates of 90 percent or more are expected.

A number of questions still remain with respect to the treatment and definition of new facility and technology definitions and targets. For instance:

- What criteria should be used to determine/select CFS (e.g., best practice, technology etc…)?
- How will "capture ready" be defined in the regulations?
- What combination of "capture ready" elements must be considered?
- All of these and more are being addressed by government, with stakeholder involvements.

Expected Canadian Compliance Mechanisms

Regulated entities will be required to meet the targets prescribed through the framework by either abating their own emissions or by making use of one or more of the framework's compliance mechanisms. **Table 3-2** summarizes the range of compliance mechanisms that are provided by the government's plan to allow companies choice in determining the most cost-effective way to meet their emission reduction targets.

Table 3-2 Compliance Mechanisms Expected in Canada

Compliance Mechanism	Compliance Year								
	2010	2011	2012	2013	2014	2015	2016	2017	2018-2030
Internal Reductions	Unlimited								
Inter-Firm Trading	Unlimited								
Early Action Credits	5MT	5MT	5MT	N/A	N/A	N/A	N/A	N/A	N/A
Technology Fund Contribution as % of Obligation	70%	65%	60%	55%	50%	40%	10%	10%	0%
Technology Fund Credits Availabile	5MT	5MT	5MT	5MT	5MT	5MT	5MT	5MT	N/A
Cost of Contribution to Technology Fund for 1tCO2e	$15	$15	$15	$20	$20 + nominal GDP growth rate	2014 price + nominal GDP growth rate	2015 price + nominal GDP growth rate	2016 price + nominal GDP growth rate	N/A
CDM Credits Allowed as % of Obligation	10%	10%	10%	10%	10%	10%	10%	10%	10%
Domestic Offsets	Unlimited								

<u>Internal Reductions and Inter-Firm Trading</u>

Internal reductions will be generated when regulated emitters achieve an emission-intensity that is below their target (in a given year). These reductions will create tradable credits for the firm equal to the difference between their target emission-intensity and their actual emission-intensity, multiplied by their production in that year. The proposed framework allows for banking of credits to be used in future compliance periods, or sold to other parties through inter-firm trading between regulated entities.

Firms that took verified early action to reduce GHG emissions between 1992 and 2006 will be eligible to apply for share of a one-time allocation of 15MT in credits, under the Credit for Early Action program. These credits will be issued between 2010 and 2012 at no more than 5 Mt per year and will also be bankable and tradable assets.

It is worthwhile to note that, under the proposed framework, there is considerable potential for significant emission credits to be achieved through co-generation use. The adjusted baseline target for co-generation facilities would be based upon the emission levels if the electricity and steam were generated separately. The emissions deemed to come from the production of heat would be based upon a conventional, stand-alone 80 percent efficient boiler. The reduction target would be 2 percent per year as per the regulatory framework. The emissions deemed to come from the production of electricity would be based upon a stand-alone NGCC generator or 0.418 t/MWh. There is no reduction target for the production of electricity.

Technology Fund & Pre-Certified Credits

Regulated firms will be able to contribute to the climate change technology fund[25] to obtain credits for compliance purposes (see table, above). The limit on contributions decreases over time, while the cost increases. The intent of the technology fund is to provide cost certainty and ease the burden of compliance in the early years of the framework. It is unclear at this point as to whether these credits will be bankable or tradable amongst regulated firms.

The final version of the Regulatory Framework released in March 2008 described another option available to regulated entities through the technology fund. The government intends to allow contributions to pre-certified projects (e.g. a CCS project) as an alternative to contributing directly to the technology fund. The contribution limits and costs for this option will be the same as for Deployment & Infrastructure component of the technology fund with one important difference: for sectors deemed to be able to make direct use of CCS technology,[26] contributions of up to 100 percent of the regulated firm's emission-intensity obligation in a pre-certified project will be permitted. The formula and rules related to pre-certified credits is a subject of intense discussion between industry and the federal government at this time.

Certified Emission Reduction Credits

Covered firms will have limited access to Certified Emission Reduction (CER) credits from the Clean Development Mechanism (CDM), up to a maximum of 10 percent of their emission-intensity obligation. All CDM project credits, with the exception of credits from forestry sink projects (considered temporary credits under Kyoto), will be endorsed for compliance with the Regulatory Framework and will be bankable and tradable.

Domestic Offsets System

In addition to internal reductions, credit for early action, contributions to the technology fund and CER credits from the CDM, as discussed above, the Regulatory Framework provides for a domestic offset system that will allow regulated firms to purchase verified emission reductions (VERs) from outside the regulated system. Banking of these offset credits will be allowed and there will be no limit on firms' access to domestic emissions offsets. A number of variables can impact the price of domestic offsets, such as: the types of projects that will eligible to receive credits (e.g., forest carbon management, no-till farming etc.); the volume of credits available for each eligible offset project type; the transaction costs associated with project development, registration and verification.

As illustrated in the compliance options summary table, regulated companies will have a variety of options with which to meet their GHG intensity targets. A temporal shift in technology and strategy can be expected, driven by regulation (2 percent efficiency improvements) at the outset and technological progress in the mid to long-term. The domestic offset system will likely represent the most significant of all compliance

[25] Component One = Deployment & Infrastructure; Component Two = Research & Development
[26] Oil sands, Electricity, Chemicals, Fertilizers and Petroleum Refining

options, starting in 2016 (when the contribution to the technology fund drops to 10percent of a firm's emission intensity obligation).

<u>Provincial Actions in Canada</u>

In Canada, a number of provinces have shown support for cap and trade policy designs to achieve absolute GHG reduction targets. At the 2007 Annual Ministers meeting, Canadian premiers were divided over efforts to develop an alternative national climate change plan aimed at trumping the blueprint put forward by the Conservative Government. The main issue of contention was over a proposal, submitted by Ontario and other provinces, to establish a cap and trade system, which was later opposed by Alberta. There is speculation that further opposition to the proposal may have come from Newfoundland and Saskatchewan, both of which have large deposits of energy resources. Of the provinces, three have been particularly supportive of a cap and trade approach to reduce GHG emissions: Ontario, British Columbia, and Quebec. Main opposition to this policy approach is Alberta, a region that has established a baseline and credit approach with intensity-based targets for large industrial emitters.

The Alberta Government claims that it is open to harmonizing its province-wide GHG regulatory regime with the federal program and remains committed to further assessing alignment and divergence issues. To facilitate, and ultimately achieve, policy harmonization between the Alberta and federal GHG regulatory regimes, a range of disparate policy design elements will have to be addressed. (See **Table 3-3**) Regulated entities that operate in Alberta will have to remain cognizant of these contrasting elements to adequately assess regulatory risk and future compliance costs across Canada, over the near and long-term.

Table 3-3 Comparison of Alberta and Federal Programs

Feature	Alberta GHG Regulation	Federal Regulatory Framework for Air Emissions
Target Sectors	All large Emitters (over 100 kt). Alberta Only	Major Industrial Sectors, Includes Power Sector
Target for Existing Plants	12% Emission Intensity Reduction	18% Emission Intensity Reduction by 2010, 2% annual reduction thereafter
Enters Force	July 1, 2007	January 1, 2010
New Entrant Treatment	Vintage dependent (2000 or later). Grace period with 2% annual reduction to 12%.	Grace period (3-years) plus CFS (yet to be defined). CCS standard in 2018.
Baseline	Average intensity of 2003-2005	Emission intensity 2006
Compliance Mechanisms	Internal reductions (EPC), trading, AB-based offset system, technology fund	Internal reductions, trading, national offsets system, technology fund, Credit for Early Action, CERs
Penalties	$200 per tonne; other fines	$200 per tonne

Unlike other jurisdictions (e.g., British Columbia) that have proposed/legislated hard GHG caps for emitters, both Alberta and the Federal Government are pursuing intensity-based targets to allow industry to continue to grow, while making improvements in the output of GHG emissions. However, the Federal Government has made it clear that it will likely move toward a hard cap system, post-2012 review period, in order to effectively align and link its program with those in other jurisdictions, namely the United States.

3.2 Projections of CCS Deployment in the U.S.

Table 3-4 shows a summary of various projections made of the need for CO_2 geologic sequestration in the U.S. under a variety of legislative and other scenarios. Quantities are shown in million tonnes per year. The last two rows show the Low and High Cases that will be used in the next Chapter to estimate the size and cost of CO_2 transportation infrastructure.

Table 3-4 Projections of CCS Deployment in the United States (million tonnes per year)

	2012	2015	2020	2025	2030
DOE NETL Accelerated CCS Technology	50		200		650
EIA Bingaman-Specter Lowest	0	0	23	87	246
EIA Bingaman-Specter Highest	0	20	251	998	1,511
EIA McCain-Lieberman Lowest	0	50	150	350	600
EIA McCain-Lieberman Highest	0	200	450	700	900
EIA Lieberman-Warner Lowest (Excludes cases in which CCS is not allowed.)	15	40	85	174	226
EIA Lieberman-Warner Highest	28	49	147	290	386
API Bingaman-Specter-like allowance pricing	0	0	0	7	31
API McCain-Lieberman-like allowance pricing	3	18	87	278	653
IPM 4P Multi-client Case	0	0	0	93	437
IPM Stringent Multi-client Case	0	0	112	441	1,243
NGC NEMS Analysis "Modest Case" of McCain-Lieberman	0	34	201	487	1,031
Average	**9**	**38**	**137**	**342**	**626**
Median	**0**	**19**	**112**	**284**	**600**
US Low Case for This Study	**0**	**3**	**25**	**100**	**300**
US High Case for This Study	**5**	**50**	**150**	**500**	**1,000**

The first projection in **Table 3-4** is NETL's "Accelerated CCS Technology Case," which is a conceptual planning scenario based on an assumption of an accelerated pace of CCS demonstration projects funded by DOE and other sources.[27] This case has the highest level of CCS in the early years, but is near the middle of the scenarios in the later year.

The next six projections shown in **Table 3-4** are EIA projections prepared for Congress of the impact of various legislative proposals as estimated by the NEMS model, the forecasting system used by EIA to prepare the Annual Energy Outlook.[28] EIA usually ran several NEMS analyses of each GHG proposal by varying assumptions related to the availability of international offsets, the availability of alternative such as nuclear power and the cost of new power plant technologies. **Table 3-4** shows the highest and

[27] NETL presentation to GHGT-8 Conference in Trondheim Norway.
[28] EIA, 2008, "Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007," EIA Report SR/OAIF/2008-01, April, 2008.
EIA, 2007, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007," EIA Report SR/OAIF/2007-04, July, 2007.

lowest levels of CCS forecasted among those NEMS analyses. For the Lieberman-Warner proposal, EIA ran two cases in which CCS was assumed not to be available and so the CCS projection was zero. Those zero-CCS cases are not included in Table 3-4 in the row labeled “Lieberman-Warner Lowest”.

The next two cases in **Table 3-4** are from a report prepared by ICF for the American Petroleum Institute (API).[29] Those scenarios are based on allowance prices expected under GHG constraints similar to those in the McCain-Lieberman and the Bingaman-Specter bills. The analysis looked only at the expected effect of the allowance prices on CCS and did not consider the financial incentives in the bills for CCS. This is why the API report’s expectations for CCS volumes are lower than those projected by EIA.

The next two cases are the projection made with ICF’s IPM® model of the electric power sector. The IPM® 4P (ICF’s expected base case that includes a carbon policy, in addition to the three regulated pollutants – SOx, NOx, Hg) and the Stringent cases represent two alternative levels of GHG control as analyzed in ICF’s Multi-client Fuels report in the Fall of 2007. The 4P case resulted in allowance prices of $32 per ton in 2030 while the Stringent Case has allowance prices of $61 per ton.

The final projection appearing in **Table 3-4** is the result of National Energy Modeling System (NEMS) model runs for members of the Natural Gas Council to analyze the McCain-Lieberman bill.[30] This run differed from those made by EIA in that it restricted the availability of nuclear power and renewable power generation and assumed less elastic supplies of natural gas. This created a case in which the reliance on CCS for coal and natural gas power plants was greater than that seen in the EIA cases of the same bill.

There is a wide range of CCS volumes anticipated among these various projections. They help illustrate the wide ranging impacts of the key factors discussed earlier in this chapter including the legal framework for GHG controls, the legal framework for CCS, level of GHG caps, availability and usability of international and domestic offsets, cost of technologies, financial incentives for CCS and ability to build new nuclear and renewable power plants. To deal with uncertainties in how these factors will play out, this report has adopted the Low and High Cases shown at the bottom of **Table 3-4**. The High Case anticipates 1,000 million tonnes of CCS by 2030 while the Low Case has 300 million tonnes by that date. These numbers can be compared against U.S. CO_2 emission from coal power plants is approximately 2,000 million tones per year. Hence, the High Case and Low Cases are roughly equivalent to having 50 percent and 15 percent respectively of the existing coal fleet capacity be operated with CCS by 2030. To the extent that non-coal fossil power plants and industrial facilities will also adopt CCS, the actual fraction of coal capacity using CCS could be lower.

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[29] “Impact of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry”, ICF International, January 2008.
[30] Natural Gas Council, 2008, “Summary of Natural Gas Council’s Analysis of Lieberman-Warner Climate Regulation Bill (S. 3036)”, June 2, 2008.

3.3 Projections of CCS Deployment in Canada

Table 3-5 shows various projections for the deployment of CCS in Canada and, in the bottom two rows, the High and Low Case adopted for this study. Much of the expected CCS in Canada would be in the oil and gas industry, in particular, emissions related to oil sands production and natural gas processing in Alberta and British Columbia. The overall level of CCS is expected to be lower than in the U.S., but is subject to the same sorts of uncertainties as in the U.S.

Table 3-5 Projections of CCS Deployment in Canada (million tonnes per year)

	2012	2015	2020	2025	2030
Alberta Saline Aquifer Project	1	7			
Alberta Gov Oil Sands CCS Target			50	75	100
Roundtable "Wedges"	5	40	75	100	130
ICO2N Accelerated Deployment in Alberta		10	25		
Evironment Canada March 2008 Lower (1)			64		
Evironment Canada March 2008 Upper (2)			92		
Average	**3**	**19**	**61**	**88**	**115**
Canadian Low Case for This Study	**0**	**10**	**30**	**60**	**90**
Canadian High Case for This Study	**3**	**30**	**70**	**110**	**150**

Notes:(1) Environment Canada Lower is 70% of oil sands and power reductions for 2020.
(2) Environment Canada Upper is 100% of oil sands and power reductions for 2020.
Excludes ongoing injections at Weyburn (~2 million tonnes/year) and gas processing plant acid gas disposal injections

The Canadian High and Low Cases adopted for this study range from 30 million to 70 million tonnes per year by 2020. By 2030 these values are 90 to 150 million tonnes.

4. CO_2 Pipeline Network Requirements

This chapter will present the compression capacity, pipeline mileage and pipeline pumping capacity needed for CCS transportation. The infrastructure analysis is based on the High and Low Cases for CCS shown in the previous chapter. For the U.S. these infrastructure planning ranges for CCS volumes are:

- 2015: 3 to 50 million tonnes
- 2020: 25 to 150 million tonnes
- 2030: 300 to 1,000 million tonnes

For Canada, the infrastructure planning ranges for CCS volumes are:

- 2015: 10 to 30 million tonnes
- 2020: 30 to 70 million tonnes
- 2030: 90 to 150 million tonnes

The translation of these volumes into transportation infrastructure requirements depends on the location of the CO_2 sources and sinks and the degree to which the CO_2 transportation system is built in an integrated manner in which costs are minimized by combining flows along similar paths into larger pipelines versus built in a piecemeal manner in which most CCS projects construct their own pipeline system.

Including industrial facilities, there are a total of over 1,700 facilities that emit over 100,000 tonnes of CO_2 per year. (**Table 4-1**) The highest projected annual volume of 1,000 million tonnes per year would be equivalent to the CO_2 amounts that could be captured at about 300 power plants averaging 500 MW in size.

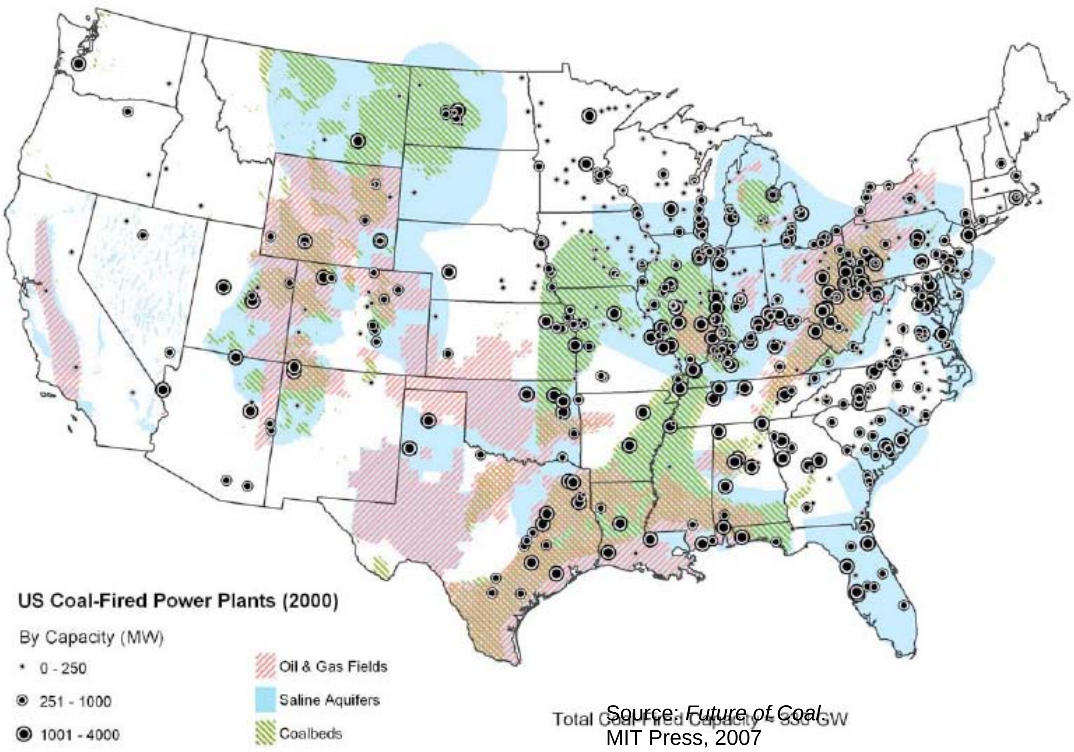
Table 4-1 Large (> 100,000 tCO_2/yr) CO_2 Sources in US (1,715 in total)

1,053 electric power plants	259 natural gas processing plants
126 petroleum refineries	44 iron and steel foundries
105 cement kilns	38 ethylene plants
30 hydrogen production plants	19 ammonia plants
34+ ethanol plants	7 ethylene oxide plants

Source: Dooley, 2007 – Battelle PNNL

The transportation issue can be illustrated with the help of **Figure 4-1** which is a map of U.S. coal power plants and areas with potential geologic storage sites. Large coal plants in the eastern, midwestern and southern parts of the U.S. are generally located an average of 35 to 60 miles from each other and, in theory, could be connected to nearby storage sites by a network of CO_2 pipelines that has a length of about 50 miles per power plant. However, this would require that a large number of coal plants use CCS and that the power plants share pipeline capacity whenever feasible.

Figure 4-1 Map of US Coal Plants and Sequestration Sites



Source: *Future of Coal*,
MIT Press, 2007

As is discussed elsewhere in this report, many people interviewed expected that the early sequestration projects would have a dedicated pipeline system and would for the most part use nearby storage sites. This expectation stems from the belief that power plants near sequestration sites would be the most economic and, therefore, would be the first to convert to or be built with CCS. Another factor was the expectation that in the early phases of the CCS industry a single entity would control the entire CCS project (capture, transport and sequestration) to better manage commercial, regulatory and liability risks. Such projects might frequently be expected to be undertaken by a regulated utility that will put the entire project within the jurisdiction of the relevant regulatory commission.

Over time, as more CCS plants are developed there will be a tendency to connect plants that are further away from sequestration sites. However, the greater density of CCS plants and increased imperative to reduce transportation costs for longer distance transportation would lead to more shared pipelines as CCS grows. Under this view, the later CCS development would tend to have larger diameter pipelines than in the early phase. The pipeline network mileage averaged per CO_2 source, may be similar between the early and later development phases, since that larger source-to-sink distances in the later phase would be offset by sharing of pipeline capacity.

Another important determinant of the evolution of the CO_2 pipeline network will be the degree to which the CO_2 will be used for EOR. As is shown in **Figure 4-1,** the spatial distribution to saline reservoirs is much wider and the estimated capacity is 175 times larger for than for EOR (see Table 2-7). Therefore, it is statistically more likely that a CO_2 source will have a suitable saline reservoir closer to it.[31] This means that if the sequestration network serves EOR to a very large degree, it will likely be transporting CO_2 over longer distance than a system that moves CO_2 from sources to saline reservoirs.

Alternative U.S. CO_2 Pipeline Network Requirements

Four cases for a CO_2 pipeline network infrastructure are shown in **Table 4-2**. Two of the cases are based on the High requirements for CCS and two are based on the Low Requirements. In turn, each of the CCS cases is evaluated under scenarios with lesser and greater use of CO_2 for EOR: 25 percent in one versus 75 percent in the other.

The High CCS Case results in additions to the existing CO_2 pipeline network (now about 3,600 miles in length) of 20,610 miles by 2030, when EOR use of CO_2 is modest in scope, and additions of 36,050 miles when EOR use of CO_2 is greater. The cost of constructing the new CO_2 pipeline for the High CCS Case ranges from \$32.2 billion to \$65.6 billion by 2030 using recent average cost factors. Because construction costs vary greatly based on the terrain through which the pipeline is built and the prevailing regional materials and labor costs, actual costs may be much greater than this.

The Low CCS Case produces a range of new CO_2 pipeline requirements by 2030 of 5,900 to 7,900 miles depending on the degree to which longer distance transport to EOR sites takes place. The cost of this new pipeline would be between \$8.5 billion and \$12.8 billion.

These results are based on assumptions for distances between captured CO_2 sources and the outputs of ICF's IPM® model. IPM® projects the amounts of CO_2 captured that would likely take place in each electricity generation area and (using the GeoCAT geosequestration cost curves) the amount to geologic sequestration that would take place in each storage area. The IPM® results were scaled to match this study's assumption for the annual CCS volumes.

[31] However, it should be emphasized that not all saline reservoirs will be suitable for long term CO_2 storage due to poor reservoir characteristics (low porosity and permeability), lack of an impermeable cap rock to restrict CO_2 escape, excessive discontinuous features and faulting, a too-thin thickness that will require a large surface area be disturbed or affected and proximity to densely populated areas that will make land difficult to assemble and facilities permits difficult to obtain.

Table 4-2 Cases for U.S. CO_2 Pipeline Requirements

High CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,250	830	500	270	100	0	2,950
Miles Needed by 2030	7,190	5,700	4,150	2,500	1,070	0	20,610
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,195	1,036	1,008	697	320	0	4,256
Expenditures by 2030	6,875	7,114	8,366	6,450	3,428	0	32,234

Low CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	140	50	0	0	0	470
Miles Needed by 2030	2,500	1,660	1,000	540	200	0	5,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	175	101	0	0	0	543
Expenditures by 2030	2,391	2,072	2,016	1,393	641	0	8,512

High CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,310	1,110	780	530	350	0	4,080
Miles Needed by 2030	7,960	9,560	8,010	6,050	4,470	0	36,050
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,253	1,385	1,572	1,367	1,121	0	6,699
Expenditures by 2030	7,612	11,931	16,148	15,609	14,322	0	65,622

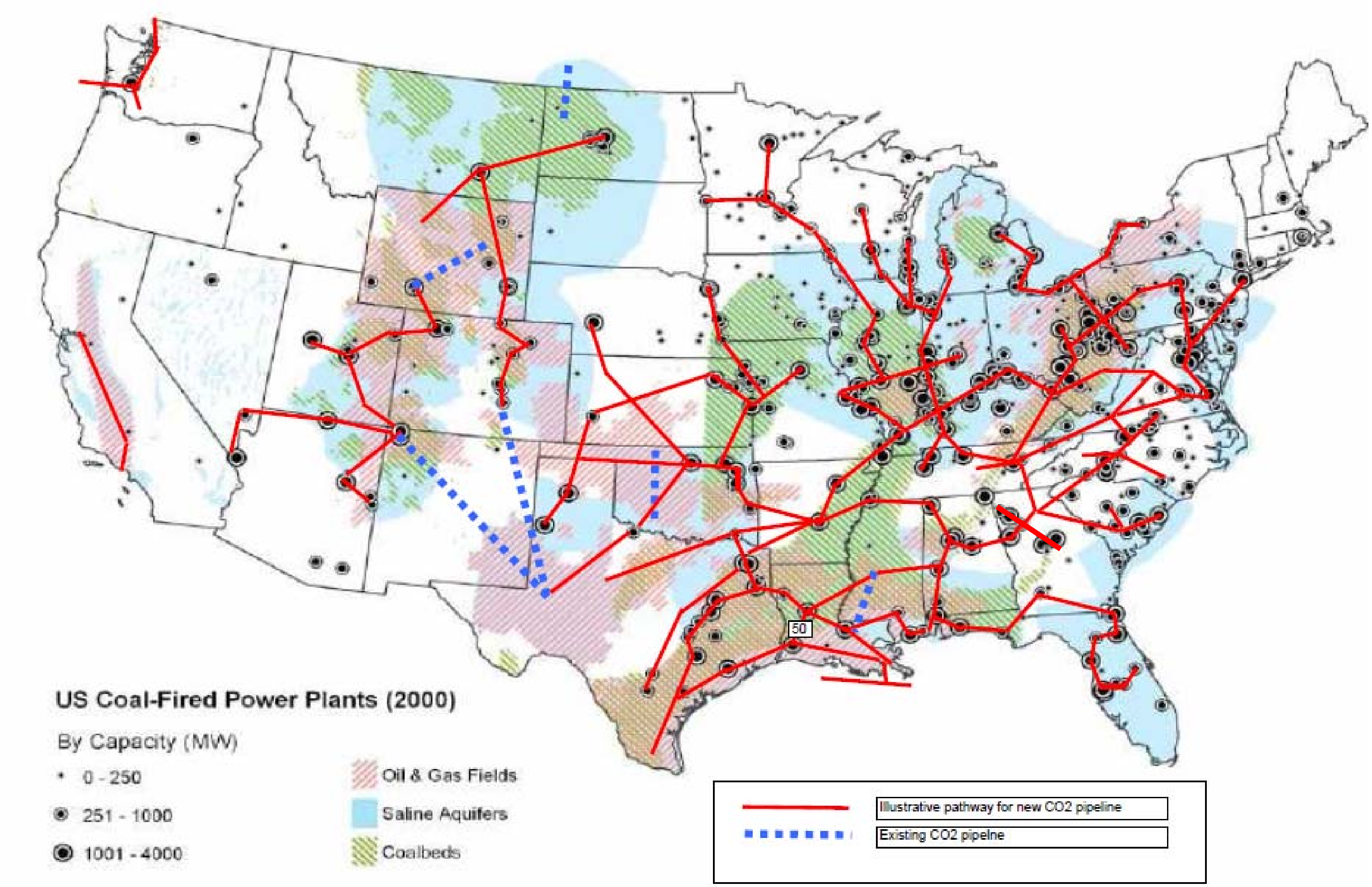
Low CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	130	40	-10	-10	0	430
Miles Needed by 2030	2,600	2,160	1,500	1,000	640	0	7,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	162	81	-26	-32	0	453
Expenditures by 2030	2,486	2,696	3,024	2,580	2,051	0	12,836

The cases with greater use of EOR are based on a more optimistic view of EOR potential that results in an EOR-related storage capacity of 50 gigatonnes versus the 17 gigatonnes for EOR sequestration in the base GeoCAT data. This larger EOR-related sequestration volume could come about through the expansion of the oil-in-place that could be targeted by what DOE refers to as “next generation” EOR technologies and the larger amount of CO_2 that could be injected into oil fields if CO_2 were abundant and less expensive than current sources.

One possible layout of the U.S. CO_2 pipeline system for the case requiring the most pipeline (High CCS Case with Greater Use of EOR) is shown in **Figure 4-2**. The new mainline corridors depicted as red lines in the map sum to 13,500 miles. Adding pipeline mileage for the expected multiple pipelines on many corridors and pipeline required to connect individual sources and sinks to the system yields the total new transmission pipeline requirement of 36,050 miles. The High CCS Case with Lesser Use of EOR would not require this degree of interconnectivity and would not show as much new capacity going into the oil producing areas.

Figure 4-2 Map of Possible CO_2 Pipeline Corridors for High CCS Case with Greater Use of EOR



Estimated U.S. CO_2 Compression and Pumping Requirements

Table 4-3 shows the estimated amounts of compression and pumping horse power that would be needed for the four infrastructure scenarios made up by the High CCS Case (with lesser and greater amounts of EOR) and the Low CCS Case (also with lesser and greater amounts of EOR).

The first column of **Table 4-3** is labeled “Compression at Plants (High-end estimate)” and represents the horsepower of compression that would be needed to bring the captured CO_2 gas from near-atmospheric pressures up to the pipeline pressure of 2,200 psi. Post-combustion capture with amine or other solvents produces CO_2 at atmospheric pressures as does oxy-firing. Therefore, this first column will be the compression requirements if such technologies (or a new technology that produces low-pressure CO_2) dominate in the capture process. The second column labeled “Compression at Plants (Low-end estimate)” represents compression needs at capture sites if IGCC’s producing CO_2 at approximately 150 psi are the dominant capture technology. About half of the planned CCS project at coal power plans will be IGCCs. If this holds true in the future, the actual compression requirements will fall mid-point between column 1 and column 2. That mid-point value is used in the fourth column that totals up all compression and pumping needed to bring the low- and medium-pressure CO_2 from point of capture into the CO_2 pipeline and the pumping needed to move the CO_2 in the pipe line to the storage sites.

The horsepower requirements for compression at the point of capture do not vary depending on whether the CO_2 is used for EOR or injected into saline reservoirs. However the pumping horsepower for the pipeline systems goes up in the cases with a high use of CO_2 for EOR because the pipeline distances are longer.

The cost of the electric-drive compression and pumping equipment is assumed to be $1,500 per horsepower. The costs of compressors and pumps in the High CCS Case range from $23.9 billion to $24.6 billion. The costs in the Low CCS Case range from $7.17 billion to $7.27 billion.

Note that **Table 4-3** does <u>not</u> include horsepower needs at the storage site itself. In order to achieve high injection rates, it may be necessary to pump up the pressure of the CO_2 arriving at the sequestration site before injection underground. The horsepower needed to sustain injection rates will depend on the geology of the sequestration site and the design of the injection wells. Moreover, if the CO_2 is used for EOR, the CO_2 will come out of the oil well along with the produced oil and will have to be recompressed to be re-injected. Since CO_2 used for EOR is re-injected once or twice (i.e., the CO_2 is injected two or three times in total) during the EOR project and need to be re-compressed from near-atmospheric pressure to (typically) well over 2,000 psi, the horsepower needed for EOR will be similar to the horsepower requirements at the point of capture.

Table 4-3 Cases for U.S. CO_2 Compression and Pumping Requirements

High CCS Case: Lesser Use of CO2 for EOR				
	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	1,027,000	513,000	25,000	795,000
H.P. Needed by 2020	3,080,000	1,540,000	81,000	2,391,000
H.P. Needed by 2030	20,531,000	10,266,000	562,000	15,960,500
	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	1,541	770	38	1,193
Expenditures by 2020	4,620	2,310	122	3,587
Expenditures by 2030	30,797	15,399	843	23,941

Low CCS Case: Lesser Use of CO2 for EOR				
	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	62,000	31,000	2,000	48,500
H.P. Needed by 2020	514,000	257,000	13,000	398,500
H.P. Needed by 2030	6,160,000	3,080,000	162,000	4,782,000
	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	93	47	3	73
Expenditures by 2020	771	386	20	598
Expenditures by 2030	9,240	4,620	243	7,173

High CCS Case: Greater Use of CO2 for EOR				
	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	1,027,000	513,000	25,000	795,000
H.P. Needed by 2020	3,080,000	1,540,000	112,000	2,422,000
H.P. Needed by 2030	20,531,000	10,266,000	984,000	16,382,500
	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	1,541	770	38	1,193
Expenditures by 2020	4,620	2,310	168	3,633
Expenditures by 2030	30,797	15,399	1,476	24,574

Low CCS Case: Greater Use of CO2 for EOR				
	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	62,000	31,000	2,000	48,500
H.P. Needed by 2020	514,000	257,000	13,000	398,500
H.P. Needed by 2030	6,160,000	3,080,000	224,000	4,844,000
	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	93	47	3	73
Expenditures by 2020	771	386	20	598
Expenditures by 2030	9,240	4,620	336	7,266

Table 4-4 shows the implications for U.S. electricity consumption of capture site compression and pipeline pumping of CO_2. For the year 2030 these uses would add

0.6 percent to 2.0 percent of the national electricity sales projected by EIA in the 2008 AEO. Adding in the electricity used at power plants for non-compression auxiliaries such as air blowers and amine pumps and the electricity needed at the injection site would increase the electricity use shown in the table by 100 to 200 percent. Electricity use will be affected by many factors, most importantly whether the CO_2 is injected at EOR sites, wherein the CO_2 will be produced with oil and recompressed for re-injection. Therefore, the High CCS Case with Greater Use of EOR would have a total use of electricity of about 6 percent of reference case national sales projected for the year 2030. By way of comparison, nearly 4 percent of the nation's electricity use now goes towards moving (80 percent) and treating (20 percent) water and wastewater.[32]

Estimated Canadian CO_2 Pipeline Network Requirements

A possible design for the CO_2 pipeline system in Alberta is shown in **Figure 4-3.** It was developed by ICO2N, a group of companies in Alberta with an interest in studying the technical and policy-related issues surrounding CCS deployment in Canada.[33] As envisioned by ICO2N, Alberta CO_2 pipelines would connect CO_2 suppliers, EOR markets and saline reservoir storage locations. The high pressure, large diameter, long distance pipeline system likely would consist of a large main line connecting the Swan Hills/Pembina/ Red Deer EOR market and saline reservoir storage locations. CO_2 supply lines from Fort McMurray (oil sands), Fort Saskatchewan (gas processing) and Red Deer (gas processing) would then be connected to this line. The main line would run by the Wabamun coal facilities enabling tie-in to future clean coal projects planned in the area. The pipeline build-up would likely take a phased approach with the first phases incorporating CCS projects currently being considered.

The total system shown in **Figure 4-3** would be 574 miles in length plus the pipelines needed to reach individual sources and sinks. If later the system is extended to the oil sand developments at Cold Lake (located east of Fort Saskatchewan), another 130 miles plus of pipeline would be needed. Connection to Peace River oil sands (northwest of Swan Hills) would add 168 miles plus of pipeline. As CCS volumes increase, some of these pipeline segments will have to be looped.

CO_2 pipelines may also be built in other Canadian provinces besides Alberta. In British Columbia this most likely would first include short-distance pipelines from gas processing plants moving CO_2 (possibly with H_2S) to nearby saline reservoirs or EOR projects. Pipelines from large coal-fired plants and other power plant and industrial sites could be built in many provinces. With the exception of EOR targets in the Williston Basin portion of Saskatchewan and Manitoba, the CO_2 sinks outside of Alberta and BC would be almost entirely saline reservoirs.

[32] Electric Power Research Institute, Inc. (EPRI) (2002) Water & Sustainability (Volume 4): U.S. Electricity Consumption for Water Supply & Treatment - The Next Half Century.
[33] ICO2N Vision, www.ico2n.com

Table 4-4 Implied U.S. Electricity Use for Compression and Pumping

	High CCS Case: Less EOR	Low CCS Case: Less EOR	High CCS Case: Greater EOR	Low CCS Case: Greater EOR
Million HP Compressors & Pumps				
2015	0.8	0.0	0.8	0.0
2020	2.4	0.4	2.4	0.4
2030	16.0	4.8	16.4	4.8
Million HP-Hours @85% utilization				
2015	5,920	361	5,920	361
2020	17,803	2,967	18,034	2,967
2030	118,842	35,607	121,984	36,068
Million kWh Hours of Electricity				
2015	4,647	283	4,647	283
2020	13,975	2,329	14,156	2,329
2030	93,285	27,949	95,751	28,312
kWh Hours of Electricity as % of US Electricity Sales				
2015	0.1%	0.0%	0.1%	0.0%
2020	0.3%	0.1%	0.3%	0.1%
2030	2.0%	0.6%	2.0%	0.6%
Required Generating Capacity (MW)				
2015	624	38	624	38
2020	1,877	313	1,901	313
2030	12,528	3,754	12,859	3,802

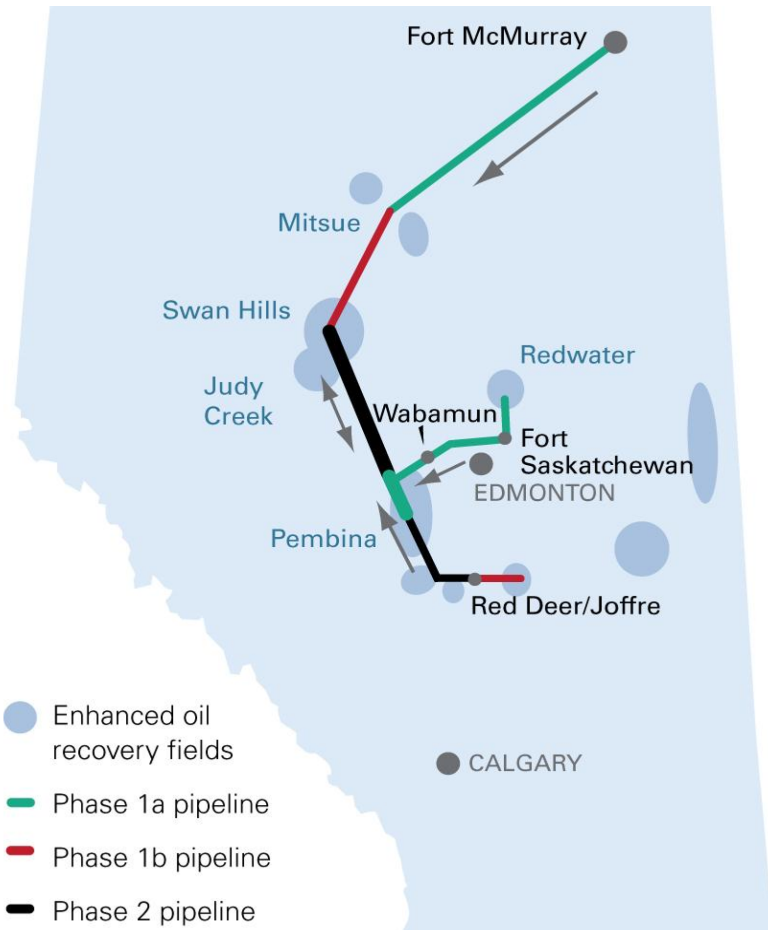
Notes:
Includes compression and pumping at capture site and on pipelines, but NOT AT INJECTION SITE. Also excludes extra auxilary power uses at power plant other than compression. Adding in all electricty use will almost double the values shown here for Less EOR cases and triple them in the Greater EOR cases..
Electricity sales in billion kWh projected by EIA in 2008 AEO are 3,869 in 2015, 4,261 in 2020 and 4,705 in 2030.

The projected total CO_2 pipeline requirements consistent with the High CCS Case for Canada are shown in the top part of **Table 4-5**. The High CCS Case for Canada reaches 30 million tonnes in 2015, 70 million tonnes in 2020 and 150 million tonnes in 2030. By 2030 approximately 3,650 miles for CO_2 pipeline would be needed. This pipeline network built through 2030 would cost $7.4 billion (U.S.) dollars.

The Low CCS Case for Canada reaches 10 million tonnes in 2015, 30 million tonnes in 2020 and 90 million tonnes in 2030. Because of the smaller volumes, this scenario has fewer pipeline miles and smaller pipeline diameters. As shown in the lower part of **Table 4-5**, by 2030 approximately 2,060 miles for CO_2 pipeline would be needed in the Low Case. This pipeline would cost $3.9 billion (U.S.) dollars.

The estimates for compression and pumping horsepower needs in Canada are shown in **Table 4-6** for the High CCS and the Low CCS Canadian cases. Compression and pumping requirements would be 2.4 million HP in the High CCS Case versus 1.4 million HP in the Low CCS Case. The range of costs for Canadian CO_2 compression and pumping equipment is $3.6 billion to $2.2 billion by 2030. As is the case for the U.S. numbers, these estimates do not include pumping or compression needs at the sequestration sites themselves.

Figure 4-3 Possible Design for Alberta CO_2 Pipeline System



Source: ICO_2N, Vision

Table 4-5 Cases for Canadian CO_2 Pipeline Requirements

High CCS Case for Canada

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	150	100	50	570	0	0	870
Miles Needed by 2020	350	230	250	1,150	0	0	1,980
Miles Needed by 2030	750	670	510	1,150	570	0	3,650

	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	143	125	101	1,471	0	0	1,840
Expenditures by 2020	335	287	504	2,967	0	0	4,093
Expenditures by 2030	717	836	1,028	2,967	1,826	0	7,375

Low CCS Case for Canada

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	50	30	300	0	0	0	380
Miles Needed by 2020	150	100	470	0	0	0	720
Miles Needed by 2030	620	300	570	0	570	0	2,060

	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	48	37	605	0	0	0	690
Expenditures by 2020	143	125	948	0	0	0	1,216
Expenditures by 2030	593	374	1,149	0	1,826	0	3,943

Table 4-6 Cases for Canadian Compression and Pumping Requirements

High CCS Case for Canada

	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	615,653	307,827	21,577	483,317
H.P. Needed by 2020	1,436,524	718,262	49,107	1,126,500
H.P. Needed by 2030	3,078,265	1,539,133	90,525	2,399,224

	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	923	462	32	725
Expenditures by 2020	2,155	1,077	74	1,690
Expenditures by 2030	4,617	2,309	136	3,599

Low CCS Case for Canada

	CO2 Compressor and Pump Requirements (H.P)			
	Compression at Plants (High-end estimate)	Compression at Plants (Low-end estimate)	Pipeline Pumps	Total (Using Mid-point estimates)
H.P. Needed by 2015	205,218	102,609	9,425	163,338
H.P. Needed by 2020	615,653	307,827	17,857	479,597
H.P. Needed by 2030	1,846,959	923,480	51,091	1,436,310

	CO2 Compressor and Pump Expenditures ($ millions)			
Expenditures by 2015	308	154	14	245
Expenditures by 2020	923	462	27	719
Expenditures by 2030	2,770	1,385	77	2,154

Other Studies Estimating of CO_2 Infrastructure Requirements

Pacific Northwest National Laboratory has performed a number of studies of carbon sequestration technologies and economics. One such study looked at the potential scale of future U.S. CO_2 pipelines.[34] The study had two scenarios. In the first scenario carbon allowance prices reached only $8 per tonne by 2030 and forecasted cumulative new CO_2 pipeline construction of 3,600 miles by 2020 and 6,100 miles by 2030. The second scenario has allowance prices that reach $52 per tonne in 2030 and has cumulative new CO_2 pipeline construction of 13,100 miles by 2020 and 19,100 miles by

[34] JJ Dooley, et. al. , "Comparing Existing Pipeline Networks with the Potential Scale of Future U.S. CO2 Pipeline Networks", Seventh Annual Conference on Carbon Capture and Sequestration, Pittsburgh PA, May 2008

2030. The PNNL results show more construction by 2020 than the cases developed for this study. By 2030 the mileage values of the PNNL report (6,100 to 19,100 miles) are similar to those presented here (5,460 to 28,780 miles).

NETL has also investigated CO_2 pipeline requirements for CCS in the United States.[35] Considering a case in which 1,750 million tonnes per year is sequestered, NETL has made a "first-pass" estimate of need for roughly 100,000 miles on CO_2 pipeline. Even after adjusting for CCS volumes, the NETL estimate has about 90 percent higher mileage compared to this study's highest estimate for 2030. NETL plans to conduct more research to make regional assessments of pipeline routes and to refine their national mileage estimate.

Comparison to Existing Oil and Gas Pipeline Infrastructure

Table 4-7 presents a summary of the expected size of and volume flows through the 2030 U.S. CO_2 pipeline systems estimated under the four scenarios and compares those statistics to similar data for the U.S. oil and natural gas pipeline systems of recent years. The expected mileage of CO_2 transmission pipeline (including the 3,600 miles of existing pipeline) ranges from 9,500 to 39,650 miles, through which will move between 300 and 1,000 million tonnes of CO_2 per year.
In comparison, the crude oil and petroleum product pipeline systems in the U.S. together are 150,000 miles in length and move 1,850 million tonnes per year. The natural gas interstate pipeline system is made up of about 299,000 miles of pipeline and moves 432 million tonnes of natural gas per year.

Transportation services are often measured in units of ton-miles, that is, the movement of one ton of a commodity the distance of one mile. The scenarios developed in this report represent between 55 billion and 563 billion ton-miles of CO_2 transmission pipeline service in 2030. In comparison the crude oil and petroleum product pipeline systems provide 600 billion ton-miles of service in recent years. The corresponding services provided by the natural gas transmission system are about 446 billion ton-miles.

On average a unit of crude oil or petroleum products moves about 324 miles through pipelines versus an estimated 1,033 miles for a unit of natural gas. In contrast the two "Less EOR" scenarios developed in this report result in an average movement of CO_2 of just 182 miles because much of the geologic storage is expected to be near the CO_2 sources. The two "Greater EOR" scenarios call for more long shipments to oil fields suitable for EOR and result in average transmission distances of 563 miles for CO_2 in the year 2030.

[35] JD Figueroa , "CO_2 Pipeline Infrastructure Study: Developing a National CO_2 Pipeline Network", Seventh Annual Conference on Carbon Capture and Sequestration, Pittsburgh PA, May 2008

Table 4-7 U.S. Infrastructure Scale Comparison: Actual Oil and Gas *versus* Estimated Future CO_2 Pipelines

	Crude Oil Pipelines	Oil Products Pipelines	Combined Crude Oil and Oil Product Pipelines	Natural Gas Pipelines	CO2 Pipelines: Low CCS Case, Less EOR	CO2 Pipelines: Low CCS Case, More EOR	CO2 Pipelines: High CCS Case, Less EOR	CO2 Pipelines: High CCS Case, More EOR
Year of Data	2004	2004	2004	2004	2030	2030	2030	2030
Transmission Pipeline (miles)	55,000	95,000	150,000	299,000	9,500	11,500	24,210	39,650
Producing Oil or Gas or CO2 Injection **Wells**	509,797		509,797	395,023	8,900	16,100	18,800	42,700
Gathering Line for Oil/Gas or **Distribution Lines** to CO2 Injection Wells (miles)	40,000	0	40,000	140,000	5,900	9,800	12,900	26,200
Total volume in **standard billion cubic feet per year** (for US enduse NG consumption or CO2 sequestered)				22,430	5,680	5,680	18,934	18,934
Total volume in **million barrels per year** (for US petroleum pipeline flow or CO2 sequestered). CO2 at pipeline conditions of 2,200 psi and about 900 kg/cubic meter.			14,600		2,097	2,097	6,989	6,989
Total volume in **million metric tons per year** (for US petroleum pipeline flow, NG consumption or CO2 sequestered)			1,850	432	300	300	1,000	1,000
Billion Ton-Miles of Annual Pipeline Transport Services			600	446	55	169	182	563
Implied **Average Pipeline Transport Distance** (miles)			324	1,033	182	563	182	563

Sources:
Natural Gas: American Gas Association, *Gas Facts 2005* , ICF estimates
Petroleum: Association of Oil Pipe Lines, 2005, *The Liquid Pipeline Industry.*
Wells: World Oil Magazine, February 2005. Currently there are about 4,700 CO2 injection wells used in EOR in the U.S.
Notes:
U.S. petroleum consumption in 2004 was 20.7 million barrels per day or 7,556 million barrels per year. Since much of this was transported by pipeline as crude oil and then transported by pipeline as products, total petroleum pipeline flows were about 40 MMBPD per AOPL.
CO2 transmission pipeline mileages include 3,600 miles of existing CO2 pipeline.
CO2 distribution lines to CO2 injection wells are included in this table for comparison to oil and gas gathering system size. Such distribution lines are not included with CO2 transmission pipeline in other tables or charts in this report. AGA Gas Facts reports only 24,000 miles of gas gathering line. This represents only part of actual systems that totals approximately 140,000 miles.

As was discussed at the beginning of this chapter, there are over 1,700 power plant and industrial facilities that emit over 100,000 tonnes of CO_2 per year in the U.S. The assumed annual 2030 CCS volumes of 300 to 1,000 million tonnes per year would be equivalent to the CO_2 amounts that could be captured at 100 to 300 power plants averaging 500 MW in size. Assuming that several dozen industrial facilities would also capture CO_2, this means that the total number of source facilities connected to CO_2 pipelines would number roughly 150 to 400 by 2030. The number of injection sites would be expected to the same order of magnitude with a larger number of sites expected in the cases with more EOR. The number of expected injection wells (shown in the second row of Table 4-7) ranges from 8,900 to 42,700 in 2030.

In addition to the large diameter (12 to 36 inches) transmission pipeline system, smaller diameter (4 to 10 inch) line will be needed to distribute the CO_2 to individual injection wells. The scenarios in which the dominant method of CO_2 storage is in oil fields with EOR will require more injection wells and more distribution lines compared to the cases in which most of CO_2 goes into saline reservoirs. The CO_2 distribution lines needed for 2030 is estimated to be between 5,900 to 26,200 miles.

5. Commercial Structures and Regulatory Framework

In this section we address the important questions of how CO_2 sequestration pipelines will be owned, financed, operated, and regulated beginning with an overview of current practices.

5.1. U.S. CO_2 Pipeline Ownership and Regulation

There is approximately 3,600 miles (5,800 km) of existing CO_2 pipelines in the U.S.[36] The major existing systems are shown in **Table 5-1**. Planned additions are shown in **Table 5-2**. All CO_2 pipelines currently are operated for Enhanced Oil Recovery (EOR). There are several pipelines that lie entirely within a single state, mostly in Texas. There are at least 6 pipelines that cross state lines[37] and one that transports CO_2 into Canada from the by-product generated by the Great Plains Coal Gasification Plant in North Dakota.

Table 5-1 Major Existing CO_2 Pipelines

Pipeline Name	Owner	From (State)	To (State)	Length (Miles)	Diameter (in)	Capcity (10^6 t/yr)	CO^2 Source	End Use
Adair	Apache	TX	TX	15	4	1	Bravo Dome	EOR
Andarko Powder River	Andarko	WY	WY	125	16	4.3	Ngas plant	EOR
Anton Irish	Oxy	TX	TX	40	8	1.6	Bravo Dome	EOR
Bravo	Oxy Permian	NM	TX	218	20	7	Bravo Dome	EOR
Canyon Reef	K. Morgan	TX	TX	139	16	4.3	Denver City Hub	EOR
Centerline	K. Morgan	TX	TX	120	16	4.3	Denver City Hub	EOR
Center Basin	K. Morgan	TX	TX	143	16	4.3	Cortez, Bravo, Sheep Mtn.	EOR
Chaparral Energy	Chaparral	OK	OK	23	6	1.3	Andarko PB	EOR
Choctaw (NEJD)	Denbury	MS	MS	183	20	7	Jackson Dome	EOR
Comanche Creek	Petro Source	TX	TX	100	6	1.3	Central Basin	EOR
Cordona Lake	XTO	TX	TX	7	6	1.3	Central Basin	EOR
Cortez	K. Morgan	CO	TX	502	30	23.6	McElmo Dome	EOR
Dakota Gasification	Dakota Gasification	ND	Canada	204	16	4.3	Gasification Plant	EOR
Dollarhide	Chevron	TX	TX	23	8	1.6	Central Basin	EOR
El Mar	K. Morgan	TX	TX	35	6	1.3	Central Basin	EOR
Enid-Purdy	Andarko	OK	OK	120	8	1.6	Ammonia Plant	EOR
Este I	ExxonMobil, et al	TX	TX	40	14	3.4	Denver City Hub	EOR
Este II	ExxonMobil	TX	TX	45	12	2.6	Denver City Hub	EOR
F. Geraldine	K. Morgan	TX	TX	12	4	1	Central Basin	EOR
Joffre Viking	Penn West	Alberta	Alberta	8	6	1.3	Petrochemical facility	EOR
Llano	Trinity CO2	NM	NM	59	12,8	1.6	Ngas plant	EOR
Pecos County	K. Morgan	TX	TX	26	8	1.6	Central Basin	EOR
Pike's Peak	Petro Source	TX	TX	40	8	1.6	Ngas plant	EOR
Raven Ridge	Chevron	WY	CO	160	16	4.3	LaBarge/Rock Springs, WY	EOR
Sheep Mountain	BP	CO	TX	408	24	11.4	Sheep Mtn./Bravo Dome	EOR
Shute Creek	ExxonMobil	WY	WY	30	30	23.6	Ngas plant	EOR
Slaughter	Oxy Permian	TX	TX	35	12	2.6	Denver City Hub	EOR
Transpetco	TransPetco	NM	OK	120	12	2.6	Denver City Hub	EOR
Val Verde	Petro Source	TX	TX	83	10	2.1	Ngas plant	EOR
West Texas	Trinity CO2	TX	TX	60	12, 8	1.6	Denver City Hub	
Wellman	Petro Source	TX	CO	25	6	1.3	Ngas plant	EOR
White Frost	Core Energy	MI	MI	11	6	1.3	Ngas plant	EOR
Wyoming CO2	ExxonMobil	WY	WY	112	20,16	4.3	Ngas plant	
Blue Lake	Blue Source	CO	CO	16	8	1.6	Ngas plant	EOR
				3,287				

Source: U.S. DOE NETL

[36] U.S. Dept. of Transportation, 2005, National Pipeline Mapping System Database

[37] Source: GAO Report to Congress: Surface Transportation: Issues Associated with Pipeline Regulation by the Surface Transportation Board. 1998. Presentation, Doing the deal: Legal and regulatory aspects of the evolving CCS regime in the USA. P.M. Marston. 2007.

Table 5-2 Planned CO_2 Pipelines

Pipeline Name	Owner	From (State)	To (State)	Length (Miles)	Diameter (in)	Capacity (106 t/yr)	CO2 Source	End Use
Beaver Creek	Devon	WY	WY	47	8	1.6	Gas processing plant	EOR
Rancher	Anadarko	WY	WY	50	12	2.6	Andarko Gas Processing Plant 2	EOR
Green Pipeline	Denbury	LA	TX	314	24	11.4	Petcoke-to-Ammonia Gasification Plants in LA and MS (3 total)	
Tinsley Field	Denbury	MS	MS	31	24	11.4	Jackson Dome	EOR
Cofeyville	TBD	KS	KS	TBD	8	1.6	Coffeyville Petcoke-to-Ammonia Gasification Plant	EOR
				442 plus				

Source: U.S. DOE NETL

Although several existing and planned CO_2 pipelines cross state and national lines, there is no definitive federal legal and regulatory framework set up for CO_2 pipeline siting and rate regulation or dispute resolution. **Table 5-3** compares the regulatory and institutional framework of oil, natural gas, and CO_2 pipelines.

The two federal agencies that may have jurisdiction over rate regulation and disputes of interstate CO_2 pipelines are the Surface Transportation Board (STB) or the Federal Energy Regulatory Commission (FERC). However, both agencies have denied that they currently have any jurisdiction.[38] In 1978 FERC held that the term "natural gas" refers to a gaseous mixture of hydrocarbons and that the goals and purposes of the Natural Gas Act (NGA) were to primarily regulate the "natural gas" industry. In 1980, the Interstate Commerce Commission (ICC), the STB predecessor agency, determined that Congress intended to exclude all types of gas, including CO_2, from ICC regulation.

However, more recently a 1998 General Accounting Office (GAO) report[39] stated that interstate CO_2 pipelines, as well as pipelines transporting other gases, are subject to STB's oversight authority. The STB may be the most likely candidate

[38] "Regulation of Carbon dioxide (CO_2) Sequestration Pipelines: Jurisdictional Issues," Jan. 7, 2008, by A. Vann and P. Parfomak.
[39] GAO Report to Congress: Surface Transportation: Issues Associated with Pipeline Regulation by the Surface Transportation Board. 1998.

Table 5-3 Matrix Regulatory Framework between CO_2, Natural Gas, and Oil Pipelines[40]

Element	Oil Pipelines	Gas Pipelines	CO_2 Pipelines
Rates Regulation Authority (Interstate)	FERC	FERC	None (Possibly STB)
Regulatory Regime	Common Carriage	Common Carriage / Contract Carriage	Private, Contract, or Common Carriage
Ownership of Commodity	Mostly third-party ownership	Mandated that interstate pipelines only transports gas owned by others.	Common for CO_2 owned by pipeline owner / third-party
Tariffs / On-going regulatory oversight	Yes - rates are approved by FERC and increase indexed to PPI +/- an increment	Yes - Rates are periodically set by rate cases before FERC	No - STB would only look at rates if a dispute is brought before it.
Rate disputes	Every five years the increment to PPI is modified.	Rare for disputes outside of rate cases. However they can be brought before FERC	Uncommon due to ownership relationships and prearranged deals
Siting	State and local governments	FERC	State and local governments
Safety	PHMSA	PHMSA	PHMSA
Market Entry and Exit	Unregulated entry and exit	Need approval for both entry (construction) and exit (abandonment)	Unregulated entry and exit
Product Quality	"Batch" modes transport different products at different times. Not	Specifications individually set in tariff approved by FERC	No Federal Regulations*
Posting information	Tariff information is available on-line	Daily operational and tariff information is available on-line	None Required
Eminent Domain	Yes - Varies by state. More often if pipeline is a common carrier.	Yes	Varies by State Law

[40] FERC – Federal Energy Regulatory Commission. STB – Surface Transportation Board. PHMSA - Pipeline and Hazardous Materials Safety Administration (Run by the Office of Pipeline Safety). PPI – Producer Price Index.

for jurisdiction over future interstate CO_2 pipelines; however, this may be clarified or changed with future legislation.

FERC is the regulating agency for both interstate oil and natural gas pipelines in regards to rates. Intrastate pipelines that do not cross state lines are subject to the individual state regulatory commissions. Some local distribution companies (LDCs), for example Southern California Gas Company in California, have large diameter pipelines as part of their systems. They are also subject to state utility regulatory commissions.

Many current CO_2 pipelines operate as private carriers, transporting for the most part CO_2 for the pipeline's owners. In a 1998 GAO[41] report, of the 14 CO_2 pipelines listed at the time, 9 were owned by oil companies or oil company affiliates. Recently built pipelines in Mississippi and Louisiana are also for EOR for fields owned by the pipeline's owners.[42] Kinder Morgan, the largest U.S. CO_2 transporter, and other pipelines also market the CO_2 commodity. In such cases, the pipeline owner owns the CO_2 in the pipeline but it is ultimately sold once it is delivered to a third-party owned oil field for EOR.

In cases where the CO_2 pipeline owners transport third-party CO_2, it can be considered contract carriage. Individual contract terms are negotiated between the pipeline and the transport customer and may differ among customers. However, at least 2 CO_2 pipelines in Texas operate as common carriers.[43] A common carrier is legally bound to transport third-party CO_2 as long as there is enough capacity, a non-discriminatory fee is paid, and no reasonable grounds to refuse to do so exist.[44] Common carriers have certain legal benefits in regards to pipeline siting (discussed below).

In comparison, nearly all oil pipelines operate as common carriers.[45] Most typically the pipeline operator does not own the oil transported. The pipeline must provide transport for any qualified customer if there is capacity available. There is "Open Access" in the sense that the pipeline cannot refuse service to a potential customer except for qualified reasons such as creditworthiness. Transport fees must also be set in a non-discriminatory manner. Common carrier status applies to pipelines engaged in interstate commerce. Many states, including Texas, also establish common carrier status for oil pipelines.

Interstate natural gas pipelines can operate as common carriers and are "Open Access" similar to oil pipelines. Any qualified shipper can acquire transport if capacity is available and they pay the federally regulated transport rate. However, natural gas pipelines can apply for negotiated rates and thus be contract carriers. Contract terms are negotiated individually between the pipeline and the customer. Potential pipeline customers still have the option of defaulting to the regulated cost-based rate.[46] This

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[41] GAO 1998.
[42] Denbury Resources. are also for EOR in their own oil fields.
[43] One of the Kinder Morgan Lines and $PSCO_2$; both in Midland Texas. Source: Texas Railroad Commission.
[44] Texas Railroad Commission http://www.rrc.state.tx.us/eminentdomain.html
[45] Association of Oil Pipelines (AOPL).
[46] Natural Gas Pipeline Negotiated Rate Policies and Practices. FERC Docket No. PL02-6-001

limits potential pipeline monopoly power. Interstate natural gas pipelines can also discount below the regulated rate as long as it is done in a non-discriminatory manner.

Interstate natural gas pipelines are mandated by federal regulation not to own any of the gas that is transported (although they may transport for a company affiliate without favoritism). Intrastate pipelines, which are common in producing states such as Louisiana and Texas, can transport their own natural gas. They operate as both contract and private carriers selling their own gas along the pipeline as well as transport only services.

Current CO_2 pipelines for EOR do not create or publish rate tariffs. They are not mandated to do so by a federal agency. The agency that presumably has regulatory authority over CO_2 pipelines, the STB, does not have on-going regulation over any pipeline that it has jurisdiction over.[47] The STB only looks into a pipeline's rates if a dispute is brought before it. It is possible that if there was a rate dispute, a pipeline customer could try to bring the dispute in front of the STB. However, there are no known cases.

Rate disputes could be rare given the current contractual setup of CO_2 transport for EOR. There are obviously no rate disputes for pipeline owner's transporting their own commodity. CO_2 pipeline laterals for EOR often go only to a specific oil field. This could limit the number of shippers on a particular pipeline. For third-party transportation, the contract terms were most likely agreed to before the pipeline was built, again reducing the potential for rate disputes.

Oil pipelines have on-going regulatory oversight by FERC. All existing and unchallenged rates were determined "just and reasonable" with the passage of the Energy Policy Act of 1992. Tariff rate increases are approved by a FERC index that is a function of the Producer Price Index plus or minus a fixed increment currently at plus 1.3 percent. [48] This increment (decrement) to PPI is modified every five years and will be revaluated in July 2011. Most rate disputes between general pipeline customers and pipeline owners are involved in the determination of the increment (decrement) to PPI. Other rate methods are available[49]. New services must be negotiated or be based on cost-of-service. Market based rates are available in certain locations with sufficient competition.

Natural gas pipelines also have on-going regulatory over-sight by FERC. Unlike oil pipelines which allow for annual transport rate increases, each individual pipeline must periodically file rate cases. The time period between natural gas pipeline rate cases varies among pipelines but can be as short as three years. Most rate disputes between shippers and pipeline owners are resolved through negotiation prior to the rate case

[47] Pipeline commodities under the jurisdiction of the STB: carbon dioxide, anhydrous ammonia, coal slurry, phosphate slurry. Source: GAO 1998.
[48] FERC Docket No. RM05-22-000. *Five-Year Review of Oil Pipeline Pricing Index.* March 21, 2006.
[49] Michelle Joy. Oil Pipeline Ratemaking Methodologies. AOPL presentation May 2004.

being formally resolved by FERC. Shippers can also dispute rates in between rate cases before the commission, but that is much less common.

A CO_2 pipeline may be built without showing public necessity. An oil pipeline may also similarly enter the market without showing economic need to a federal agency. An interstate natural gas pipeline, however, must obtain a Certificate of Public Convenience and Necessity. In essence a natural gas pipeline must show to federal regulators that it is in the public interest. Usually signed long-term transportation contracts are sufficient to prove that there is a market demand for a natural gas pipeline. (FERC also allows pipelines to build a portion of the proposed capacity "at risk," i.e. some portion of the capacity can be in excess of the total contracted amount and still be deemed in the public interest.)

Both CO_2 and oil pipelines may take the pipeline out of service (leave the market) for economic reasons without federal approval. An interstate natural gas pipeline must apply for abandonment before it is allowed to cease operations. All types of pipelines must follow environmental and safety regulations when a pipeline is taken out of service.

Current CO_2 pipelines do not have filed tariffs, and therefore obviously cannot post them online. Both oil pipelines and natural gas pipelines have tariff information available either on the FERC website or their own. Oil pipelines are only required to post terms related to fees and rates. Interstate natural gas pipelines not only post rate terms by posting their full tariff, but they also post daily operating information. The daily operating information lists available pipeline capacity which might be useful for a potential shipper.

CO_2 pipelines are not regulated in terms of product quality. For third-party transport of CO_2, this is most likely spelled out in the individual contract terms between the shipper and the pipeline. However, if future federal regulation is proposed, the Interstate Oil and Gas Compact Commission (IOGCC) would prefer a performance based standard, as opposed to a rigid percentage standard. The CO_2 should of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir in which it is injected.[50] The IOGCC is in favor of keeping such regulations under state control as opposed to federal.

Natural gas product quality standards for interstate pipelines are described in the posted tariffs. Initial and any modifications to the quality standards must be approved by FERC. Shippers on the pipeline can comment file their own comments to the FERC for or against when any changes are proposed.

Product quality standards for oil pipelines can be more flexible. Oil and oil products can be sent down the pipeline in batches. There is less mixing of the streams in oil pipelines as composed to natural gas. Therefore, an oil pipeline can have different quality standards for different customers at different times.

[50] Marston, October 2007.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has jurisdiction over CO_2 pipelines in regard to pipeline operation and safety.[51] The PHMSA goals include: increase pipeline safety, reduces environmental impact of pipeline transport, help maintain reliability of the pipeline systems, enhance pipeline standards across national boundaries, and increase emergency response preparedness.[52] Oil and natural gas pipelines also fall under PHMSA jurisdiction.

Starting and ending points for current CO_2 pipelines used for EOR are determined by the CO_2 source and oil field location. Pipeline route selection or siting is driven mainly by a number of factors including environmental concerns, access availability, and costs. Pipelines will follow existing utility easements and rights-of-ways when possible. State regulations for route review or approval vary. Some states have a regulatory process for certifying that the pipeline is in the public's interest in the event the pipeline company has to exercise the right of eminent domain for acquiring a portion of the route. In Texas the pipeline must be a common carrier to obtain eminent domain powers.

The number of permits state, local, and federal necessary for pipeline construction will vary by route. There is no overall federal agency permit necessary but possible Federal permits that may be required include: the U.S. Army Corps of Engineers, the U.S. Fish and Wildlife, the U.S. Department of the Interior, the Bureau of Land Management (BLM); the U.S. Department of Agriculture, Forest Service (FS), the U.S. Department of the Interior, and the Bureau of Indian Affairs (BIA) Pipelines may need state permits from such agencies as a Department of Natural Resources, Pollution Control Agencies, State Historical Preservation Offices, or Agricultural Departments. Most likely if a CO_2 pipeline does not significantly impact federal lands or waters of the U.S., it will not need an Environmental Impact Statement (EIS) but may need and Environmental Assessment (EA). If no Federal lands or waters of the U.S. are crossed, only state approval may be needed.

Oil pipelines have similar siting requirements as CO_2 pipelines. Although FERC regulates matters in regards to rates, it does not have oversight over pipeline routing. Oil pipelines will also need permits from the varied assortment of state, federal, and local agencies stated above even though there is not an overall permit necessary by a single agency.

Interstate natural gas pipeline siting and route selection does require a FERC approval unlike oil or CO_2 pipelines. Natural gas pipelines also require various federal, state, and local agencies. EISs are necessary for all major pipeline construction projects.

5.2 Canadian Pipeline Ownership and Regulations

There are existing CO_2 pipelines in the Western Canadian Sedimentary Basin that are used to transport CO_2 and H_2S from gas processing plant to underground disposal sites. These pipelines are under the jurisdiction of the provinces and must comply with

[51] The PHMSA is within the Department of Transportation's (DOT).
[52] www.phmsa.dot.gov/about/mission

provincial pipeline siting and safety regulations. The status of all these pipelines with regard to economic regulations is unclear, but they are thought to be producer-owned and ship only their owners' gas.

The only CO_2 pipeline falling under the National Energy Board (NEB) is the Souris Valley CO_2 Pipeline connecting the Weyburn Enhanced Oil Recovery (EOR) project in Saskatchewan to the U.S./Canada border crossing near Estevan, Saskatchewan to which the CO_2 from Dakota Gasification Facility in North Dakota is delivered. Souris Valley Pipeline is a wholly owned subsidiary of the Dakota Gasification Company.

The NEB has jurisdiction over inter-provincial and international gas, oil and commodity pipelines. The NEB issues certificates of present and future public convenience and necessity, regulates "just and reasonable" tolls, issues construction and safety regulations for onshore pipelines and has the power to require pipeline companies to provide facilities for new customers.

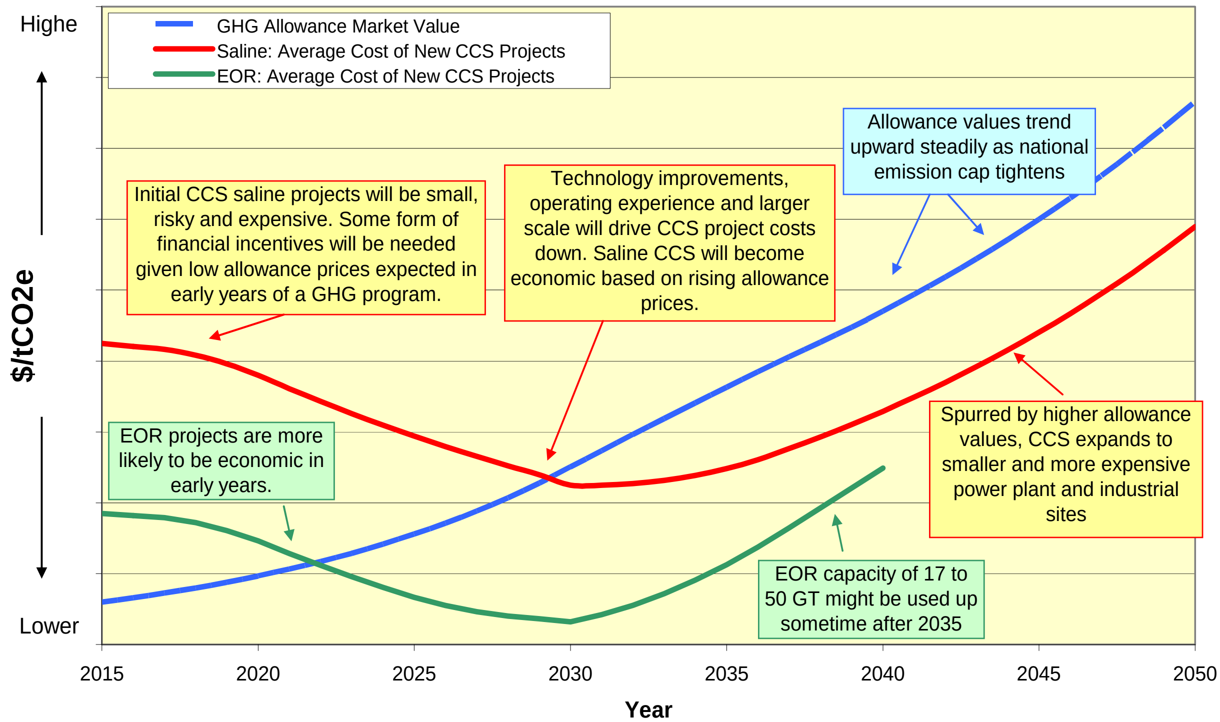
5.3 Major Commercial and Regulatory Issues for CO_2 Pipelines

This section reflects the interviews ICF conducted with a number of industry and government representatives. From these interviews we have attempted to distil the most common themes as well as key insights provided by the interviewees. We have not identified particular interviewees or for the most part the industries they represent.

Much of the discussions focused on the totality of the costs of CCS (that is capture, transmission, and storage) and how the GHG control program could evolve. **Figure 5-1** below represents conceptually how CCS economics might develop. Initially, CCS costs will be high relative to the value of carbon allowances as set by regulation and the market. During this period, there may have to be subsidies or other government support of CCS projects from power plants and industrial fuel combustion sources. Subsidies may not be needed for projects in which a high-purity industrial CO_2 source is captured and where the CO_2 will be used EOR. Over time, costs for projects based on power plants and industrial fuel combustion sources should fall with the construction of more and larger systems and improvements in capture technology. Meanwhile, carbon prices should increase as the national emissions cap is tightened. At some point, the two trends cross where carbon prices alone can support further CCS. In the longer term, smaller and more expensive CO_2 sources will become economic to capture as tightening national GHG caps increase allowance values. This will cause the average cost of CCS project to go up along with the allowance values.

Figure 5-1 Potential Development of CCS Economics

Conceptual Representation of a Possible Trends in GHG Allowance Price and Average Costs of New Saline and EOR CCS Projects



As a basic observation we would note that pipeline issues are not viewed as the critical path for CCS at this time. When pressed on details of how a pipeline industry might operate, most deferred to current pipeline practices, and particularly to natural gas as the model, although this was more a matter of default than of detailed assessment (with a couple of exceptions.) Rather the major issues that concern many who are involved in CCS policy development are the technologies and costs of capture and the location, planning, design, operation, and maintenance of sequestration reservoirs. Consideration of the appropriate regulatory framework for a CO_2 pipeline industry requires an understanding of its potential commercial and operating structures.

In the United States, natural gas and petroleum pipeline regulation evolved separately under different historical and commercial circumstances, resulting in two different regulatory models (utility and common carriage).

Oil pipelines evolved as common carriers, since they did not own the oil they carried, and were regulated as such by the Hepburn Act of 1906 which brought oil pipelines under the Interstate Commerce Act of 1887. While the Interstate Commerce Commission regulated their rates, tariffs and terms of service, and accounting, it did not regulate entry and exit, asset sales, securities transactions, or non-transportation services.[53] Interstate natural gas pipelines on the other hand began as private carriers who owned the product they carried. The Natural Gas Act of 1938 resulted in their being regulated as utilities, that is, as natural monopolies, not common carriers. Under this model, construction and siting, entry and exit, asset sales, securities, rates, tariffs, and terms of service all are subject to regulatory oversight. FERC Order 636 and the other reforms of the 1980s and 1990s have not changed this basic model, even though interstate pipelines no longer own the gas they transport and have open access requirements.

Thus, how a CO_2 pipeline network evolves may suggest one or another model for regulation. Below we consider some of the alternative structures for CO_2 pipeline industry. We have arranged this discussion around specific issues. Much of the insights here are from interviews ICF conducted with key people in industry and government and from these interviews, several issues emerged as affecting how parties see development occurring and ultimately the optimal regulatory framework.

- Liability for performance of both the pipelines and the sequestration reservoirs in short term and long term. Liability refers both to the safety and the efficacy of the system in permanently storing carbon.
- Financing of pipeline and sequestration facilities can be accomplished in several ways, from corporate balance sheet financing (probably for the smaller projects), to project financing, to hybrid approaches including some public financing.
- Siting and right-of-way acquisition concerns whether federal eminent domain is desirable and the overlapping authorities of federal, state, and local siting processes.

[53] Steven Reed, “The History of Oil Pipeline Regulation,” presentation to the FERC, May 18, 2004.

Alternative Ownership Structures

As described more fully in the next section, CO_2 pipelines currently operate in close integration with EOR projects, where owners of pipelines often own a CO_2 source and an EOR opportunity. The pipeline is thus integrated with the facilities at either end of the system. The interviewees offered several suggestions about structures that depend on specific project circumstances. They generally fall into the following categories.

- On-site Sequestration Model. A CO_2 producer (say a large power plant) pipes CO_2 to a sequestration structure on or near the site of the plant. The producer would own the pipe and the sequestration structure, with the pipe being a very short conduit to sequestration. In this case the producer of CO_2 owns the pipeline and sequestration facilities, as well as the CO_2 itself. This may have limited application beyond the early pilot projects and demonstration phases for proving CCS' viability.
- Project Ownership Model. A producer enters a partnership or a long term contract with a sequestration site developer and pipeline operator (who may be the same entity) for transporting CO_2 from the plant site to the sequestration reservoir. The producer may be an owner of the downstream CO_2 facilities and CO_2 or may only contract for services. This model could take several forms. In one a group of coal-fired utilities could band together to sponsor a pipeline and sequestration system, with the latter operated by a specialist. The utilities would be contract shippers.
- Municipal Solid Waste Model. A producer contracts for CO_2 removal services with an independent collector pipeline/sequestration service provider who transports and sequesters the CO_2. The producer does not own the CO_2 once it leaves the plant.
- Public Utility or Government Ownership Model. An independent corporation collects and sequesters CO_2. This would be an independent entity, similar to the regional power administrations (TVA, BPA), or the civilian nuclear waste program in the Department of Energy under Nuclear Waste Policy Act (1982).[54] It could also be a public utility that has some or all private ownership.

Each of these models suggest different trajectories of development and the ultimate shape of regulation. Several interviewees noted that it is likely that the current CO_2 pipeline structure that supports EOR projects would lead the way in any CCS-based industry, where the initial CCS projects would likely be for EOR, with pure sequestration developing later. (There is a concern that EOR would not receive the full GHG credit that pure sequestration would receive. But then depending on the price of oil, maybe that is not a deal breaker.) Under this trajectory, current CO_2 pipeline companies may develop sequestration sites, contract for CO_2 from producers, direct CO_2 to EOR projects with the capability in time of diverting CO_2 into sequestration sites. Under this

[54] However, it must be noted that the civilian nuclear waste program has yet to establish a national repository for waste.

case, the sequestration and pipeline would be integrated entities. This approach also suggests a private carriage or contract carriage pipeline system.

An important issue that cuts across all commercial structures is whether CO_2 pipelines that receive product from industrial sources could be structured as Master Limited Partnerships (MLPs). MLPs, which have certain tax advantages over corporate entities, are common in the natural gas and oil pipeline sectors. Under current regulation, CO_2 pipelines serving EOR projects and deriving their product from wells are allowed to operate as MLPs because of the depleting nature of the well-based CO_2 supply source. Industry sourced CO_2 would not qualify the pipelines to operate as MLPs under current regulation. This issue was raised in the interviews that were conducted and is viewed as a potential obstacle to the development of CO_2 pipelines.

<u>Access to the Pipeline System</u>

This issue concerns how new producers of CO_2 will access pipeline capacity. Under common carriage, carriers must take all comers; capacity on the system is prorated across all the shippers, old and new. Under the FERC utility regulation, pipelines must provide open access in a non-discriminatory manner, but the shippers must execute private contracts and pay for incremental capacity if new capacity is needed.

Almost all of the interviewees lean towards a private contracting approach similar to the way in which natural gas pipelines operate. The general sense is that the early CO_2 pipes will be project specific deals between producers and operators of pipes and sequestration sites. Initially there would be a one or a group of producers who would provide the core volumes to sponsor a given pipeline/sequestration development. This could consist of a trunk line fed by individual lines from the producers. At the delivery end, CO_2 would be deposited in one or more sites. Commitments between the parties could be based on contracts in much the same way as the LNG value chain, with its substantial investment, depends on back-to-back contract commitments of all the parties – suppliers, shippers, receiving terminals. Some interviewees felt that regulation may be appropriate at this point. Others believe that regulation would arise after several such projects developed and the opportunities for networking systems arise. At that point regulation mandating open access may be required.

A common carriage approach would involve an independent third party constructing a pipeline and sequestration site that is proximate to a number of producers, who may sign up as shippers. The problem with this structure is that under common carriage, capacity is prorated among shippers, such that a shipper may see its capacity reduced to accommodate another shipper. A producer then may end up venting CO_2 because his capacity is reduced. The producer must find an alternative storage site or would be forced to purchase emission credits or offsets.

<u>Pipeline Siting</u>

Most interviewees see the major role for federal regulatory authority in providing centralized review of routing, siting, and environmental impacts. At present, no such authority resides with any federal agency. DOT provides safety performance regulatory authority over CO_2 pipelines. States provide the siting and environmental review, except where pipes cross federal lands or waters of the U.S. Current CO_2 pipeline operators do not express a need for federal oversight, given their experience with state review agencies has been satisfactory. However, the existing CO_2 pipelines are in the west, where in general there is ample room for routing, unlike eastern states where population is denser.

The granting of the right of eminent domain to CO_2 pipelines, a key element of FERC authority over interstate gas pipelines, currently resides in the states. Some states appear to be willing to give CO_2 pipelines eminent domain authority in return for greater regulatory oversight. To date this has included review of rates and tariffs conditions. Even with this, economic regulation of the pipelines has been light handed, mainly relying on filed complaints to engage any review of practices. Eminent domain, which allows pipelines to take land for right of way, presumes a FERC style of regulatory oversight, and not common carriage, at least as it is practiced today. That is, in order to receive the right to condemn land the pipeline must demonstrate some public interest. The government then can require rate and tariff oversight, in addition to siting, but may also involve approval of costs and post construction activities.

Eminent domain authority under state law may be adequate for small CO_2 pipeline projects in a few states (Texas and California, for example), but state authority will be inadequate for major, multi-state projects. New federal legislation ultimately will be needed, but any expansion of federal rights will be highly controversial and will face possible opposition in Congress. Federal authority could be in the nature of a certificate of public convenience and necessity (similar to the NGA), a licensing approach (similar to Part I of the FPA (this may be more appropriate for privately-owned CO_2 repositories), or the sort of "backstop" siting authority (a federal construction permit) that FERC obtained under EPAct 2005, following designation of the corridor as a national interest corridor by DOE.[55]

Cost of Service and Rate Regulation

Most interviewees had no views on pipeline rates, whether they should be regulated, and how they should be designed. Those who had considered the question believed

[55] There are parallel legal and regulatory issues for geologic sequestration include resolving rights to underground pore space and whether and how use of pore space will be paid for – legal areas that are now primarily under the purview of the States. Several key questions are who owns the pore space and whether those property owners need to agree to lease their property for geologic storage or can it be condemned by eminent domain or other processes akin to forced unitization. Other questions include whether compensation is owed to pore space owners far away from the injection well site when a CO_2 plume – several years after the injection ceases - migrates into their property. A related question is whether compensation is owed for significant pressure increases in an underground reservoir even in the absence of a CO_2 plume in the subject property. The CO_2 plume might take up several 10s of square miles in a saline reservoir over a 20 to 40 year injection period for one 500 to 1,000 MW coal plant and significant pressure increases could be felt over 100s of square miles. It may be very difficult to assemble land rights for geologic sequestration if the pore space is declared to owned by the land owner (i.e., not public property such a airplane flyover rights) and private negotiations have to be relied upon.

that the shipping rates should be market-based and negotiable. The argument is that given the risks inherent in a start-up industry, rate regulation based on cost of service principles and authorized rates of return would not provide the incentives to undertake the investment.

Permitting and Public Safety

CO_2 pipelines are regulated by the Department of Transportation, PHMSA. The safety record of the industry has been good. Current pipelines believe the PHMSA provides sound, workable guidelines for design and operational safety performance. At present there are no obvious reasons to change the current arrangement for future CO_2 pipeline development.

Other Issues Raised in Interviews

Who would own the CO_2? Many producers would prefer to transfer ownership of the CO_2 at the plant gate and have no other responsibility for it. This is the municipal solid waste model. The question then is whether the pipeline/sequestration entity would own the CO_2 or would a third party middleman take ownership, e.g., a bundler, or possibly the government? Many in the oil and gas industry would prefer to own and operate the sequestration sites, based on their experience in reservoir engineering and design. They nevertheless would want some government indemnification for long term leaks after some initial operating period, as well as local effects on groundwater and any pooling of leaks

Who would set CO_2 quality specifications? EOR requires certain CO_2 composition specifications and pipelines require some standard CO_2 specification to ensure ongoing pipe integrity. Some interviewees believe the government should establish a standard; others believe it is the pipelines that can set standards. One concern is that producers will include other unwanted gases in the CO_2 stream, which makes it unusable for EOR, possibly problematic for transporting gas, but probably not a problem in the sequestration reservoir. Other interviewees are opposed to any CO_2 specifications, because different capture technologies result in different stream content. Having specific specifications may inhibit pipeline materials research and development. There also has been the suggestion that CO_2 could be batched to meet differing quality standards for EOR or sequestration. If there are to be quality standards applied to CCS, then producers will have met those standards with equipment on site to strip out unwanted compounds.

What should be the role of government in the development of a CCS system? There are divergent views on this question. Some maintain that in the early phases of development where EOR projects would dominate, there may be a limited role for the federal government. This view believes that the role would increase as more pipelines are constructed and some form of regulation would become necessary for siting, environmental performance, and the like. At one end of the spectrum, there would be no government oversight of rates, with all rates set in bilateral agreements. Others can see that there may be a cost, rate, and performance overview. At the other end of the spectrum there could be government ownership of or participation in actual projects. Or, the government could provide some financial guarantees. Examples include the federal highway system, the SPR, TVA, and the St. Lawrence Seaway. Canadians are more likely to consider an activist government role in the development of the infrastructure.

One interviewee proposed some sort of federally chartered entity that would manage the pipeline system and storage sites, or provide a financial backstop for a privately implemented system. Funding could be provided by a millage rate on fossil-fired generation. This would free the government entity from the federal budget cycle and the risk of political interference with its funding and operations. (See summary of H.R. 6258 below.)

Another major question is whether the government should shoulder the performance liability of the sequestration reservoirs. (There is generally less concern about the performance of the pipelines themselves – that is, the pipes hold the gas only for a short time and the technology is developed that performance does not seem problematic.) Most seem to believe that there is a major role for the government in the long term operation and maintenance of sequestration sites. There also may be a role for a government body (United States Geological Survey or EPA) to identify and classify reservoir sites according to standard performance criteria, ranking reservoirs as say "AAA" to "BBB," where rates for storage or credits may reflect the performance criteria.

<u>How will the system be financed?</u> The major financing concerns are with the sequestration sites, less so in the pipelines. The major technology and performance risks that are critical to financing are in sequestration. It is generally believed that the pipeline network can be financed through a combination of project and corporate debt, supported by shipper commitments. Very short pipelines (where a power plant is located at or near a sequestration site) can be financed with corporate debt. Longer pipelines and 'backbone' pipelines will require some up-front project financing supported by long term contracts. However, there are some who believe that other than EOR supported pipelines, any major construction effort will require some form of government support at least in the early development of CCS. This raises the question of whether some government financing entity will have to be put in place.

(Along these lines we should note the introduction in June 2008 of the Carbon Capture and Storage Early Deployment Act (H.R. 6258), which would set up the Carbon Storage Research Corporation under EPRI to fund research into accelerating the commercial availability of CCS technologies. Funding would be provided by assessing fees on distribution utilities for all fossil fuel-based electricity delivered to retail customers.)

Financing will be affected by the commercial structure of the operating entities. One interviewee pointed out that is would be more desirable for the pipelines to be MLPs as many current pipelines are (CO_2 and natural gas). Law restricts MLPs to shippers of depleting resources. Thus to attain MLP status, some legislation would be required.

Who should regulate a national pipeline system? The frequently expressed view is that a CO_2 pipeline network would look something like a natural gas pipeline system, and in this case FERC would be the logical regulatory entity, based on its experience with pipelines. From our interviews, it would appear that they may be willing to take on the role. As noted above, some view the current CO_2 pipeline regulatory system as adequate but anticipate that over time the federal government will have a larger role.

6. Regulatory Options for CO_2 Pipelines

The issue of how CO_2 pipelines might be regulated will be considered in the context of a national GHG policy. Should GHG legislation be enacted, CCS will be but one of many measures that will be available to reduce GHG emissions. When and where CCS is the most economic approach will depend on the shape of ultimate GHG policy, technology advances, public acceptance of each mitigation option, and the costs of all alternatives. In any national GHG program, government will play a significant role in several key areas:

- establishing the value through time of avoided CO_2 emissions;
- permitting storage sites and certifying GHG credits for storage;
- establishing a legal framework for long-term responsibility for post-closure maintenance of CO_2 storage sites; and
- developing the legal and regulatory basis for a rational CO_2 transportation system that meets some standards of "public convenience and necessity."

The existing pipeline network for delivering natural and anthropogenic CO_2 to EOR projects has evolved under a unique set of circumstances that may offer little guidance to a national CCS program. Except for safety regulation by the PHMSA there is no national regulatory system for the industry. Siting and operating issues have fallen to state authorities or federal land management agencies as appropriate. The key question of eminent domain is determined on a state-by-state basis. In general, this system appears to have worked without controversy. The operating pipelines are mostly in the far west along corridors with low population densities and the CO_2 they transport provides a valuable economic service to EOR operators.

The need for federal regulation of future CO_2 pipelines connecting industrial and power plants with storage will arise from conditions very different from today's EOR-based CO_2 pipeline industry. First, CO_2 from these sources may have no economic value independent of that which government policy may determine for the avoidance of its release to the atmosphere. Captured CO_2 will be a by-product for which companies will have to invest large sums of money to transport and store. This is why municipal waste is often cited as the most apt analogue to CCS. Second, much of the CO_2 pipeline infrastructure for a national GHG program will be developed in more densely populated areas, making siting and routing more complicated and controversial. In this context, some kind of centralized review and approval authority for CO_2 pipelines may be necessary to ensure the execution of national policy. The key regulatory questions relating to these conditions are presented in **Table 6-1**.

Table 6-1 Federal Regulatory Options for CO_2 Pipelines

Area of Potential Federal Regulation	Pros	Cons
1. Federal jurisdiction for commercial regulation in one agency	Current confused state of affairs may not support the large potential CO_2 pipeline investments needed in next 20 years.	Although some clarification by Congress may be inevitable, objections may be raised by states and special interest groups (industry, environmental, local government, etc.).
2. Economic Regulation, Rates	Provide more certain costs for shippers and adequate returns for pipelines.	May hinder early CO_2 pipelines' profits from innovative contract terms with shippers given that volume flows will be uncertain.
3. Common Carriage Regulation	Ensure access for all CO_2 producers.	Where capacity is prorated, may not provide assurance of adequate disposal of captured CO_2
4. Private Contract Carriage	Would provide performance assurance, especially for first movers, and provide contract commitments for financing.	May reduce access to the system.
5. Access to Pipeline Capacity	Requiring open access through common carriage would encourage fewer pipelines to be built, better economies of scale.	Economic incentives can lead to optimally sized pipelines in any case. If pipeline developers or shippers want to tie up capacity for themselves (e.g. to support CCS projects planned for the future) they should be able to do so.
6. Federal Lead for Environmental Reviews (e.g., Hackberry for LNG terminals)	Will reduce burden to pipeline developers and make CCS more economically viable.	Would upset state officials and lead to backlash among citizens against CO_2 pipelines and CCS.
7. Federal Eminent Domain	May be needed to improve planning and system wide design and operating efficiencies.	May create backlash among property owners. Trade off for ED might be impractical rate regulation.
8. Federal Corporation for Storage Development and Operations	Would provide a federal commitment towards a broadly social goal.	May stifle private sector opportunities and depending on how structured could result in political considerations driving decision making.
9. Market Entry and Exit Permission for Interstate CO_2 Pipelines	Would likely be tied to other regulations. Incentive to regulate might be to limit environmental foot prints of similar projects that can be consolidated.	No reason to restrict entry or make it more burdensome.
10. Product Quality	Federal standards may help reduce environmental concerns. Would allow linking of separate systems in the long-run.	Might restrict most the economic choices (e.g. Oxy-firing of low-sulfur coals without an FGD). Work-around might include a "clean CO_2" spec for EOR and a "dirty CO_2" spec. In the long run pipeline quality specs may have to be tied to EPA underground CO_2 injection rules.

Federal Jurisdiction

The principal need for regulation is to ensure a timely, adequate, and rational pipeline system that meets national policy objectives for carbon sequestration. This could mean a mixture of both state and federal regulatory oversight, as in the natural gas pipeline industry today. Viewing the map at figure 4-2, one can expect that the initial CO_2

pipelines might be built to nearby EOR or other storage sites and could be entirely within a single state. In such cases states may regulate the pipelines as are done now. As the system expands, with pipelines receiving CO_2 from more facilities, crossing state boundaries to reach more distant storage sites, involving more complex pipeline configurations (such as intermediate short term storage to manage surges in supply), and interconnections with other CO_2 pipelines, the need for federal jurisdiction over the system becomes more apparent.

The logical agency for overseeing CO_2 pipelines may be FERC, given the similar technologies, siting issues, and environmental impacts to those of the natural gas pipeline industry. Similarly, the certification process for CO_2 pipeline could be modeled on NGA regulation. Safety jurisdiction can remain with PHMSA, just as it is for natural gas pipelines.

A principal focus of regulation would be in constructing and maintaining an efficiently operating pipeline network that ensures the delivery of CO_2 to storage sites. FERC could have the authority to direct pipeline interconnections and require the industry to take steps to operate in an integrated fashion. Abandonment of facilities or ownership would have to be approved by the FERC. Similarly, the regulator should ensure open access to pipelines and prohibit any undue discrimination in rates and services.

Economic Regulation

As is the case now, CO_2 pipelines in the future could offer market based pricing for services, operating under contract carriage principles, where parties negotiate a transportation fee. This approach may offer greater incentives for the development of early pipelines, especially where those would be intended for EOR sites, than a regime that imposed 30-year levelized cost-base pricing.   This approach, however, could create problems of market power as more shippers seek service over existing pipes. The pipelines in this case would have a bargaining advantage. Pipelines should not be in a position to capture all of the benefits of CCS. One recommendation is to have a system of maximum rates; another would be to have a complaint process with regulatory review as is done with intrastate pipelines and oil pipelines. Pricing principles should aim at sharing the benefits (if any) of CO_2 storage.

Pipelines should able to operate as third party transporters as well as integrated pipeline and storage service providers, consistent with the municipal waste analogue.

There may evolve national operating rules across the industry such requiring posted max-rate pipeline tariffs. CO_2 product quality can be an individual pipeline tariff issue and can vary depending on whether CO_2 is destined for EOR sites or simple storage. While we would expect that large trunk pipelines should have open access requirements. However, there may be some dedicated pipes over short hauls where open access may not be appropriate. Parties could be able to appeal to the regulator with complaints about service, access, or rates.

Siting.

Siting of CO_2 pipelines will become a major public concern as the system expands beyond the short haul pipelines and EOR projects located in sparsely populated areas. Public acceptance of large CO_2 pipelines could be problematic, just as it is today for natural gas pipelines, electric transmission lines, and many other large, energy-related projects. One objective of federal regulation would be to manage public participation, ensure adequate environmental and land use review, and that pipelines are constructed with minimal impact on people and the environment.

On the state level, for short pipelines and intrastate EOR projects, current state siting and environmental decision making could continue to operate as it currently does. For pipelines under federal jurisdiction, the jurisdictional agency should be the coordinating agency for federal and state reviews and approvals.

The federal jurisdictional agency approval should statutorily come with the power of eminent domain. Some commenters do not believe this is necessary, but experience to date with CO_2 pipelines has been in the far west. In the more densely populated areas, right-of-way acquisition without having condemnation powers may be impossible, especially where there is intense opposition.

APPENDIX A. DOE CO_2 Sequestration Pilot Projects

The table below summarizes the available information on several of the planned DOE sequestration pilot projects. The table was prepared in early 2008 with information available at that time. An update of all DOE sequestration pilot project activity was beyond the scope of the current project.

Table A-1 Planned U.S. Department of Energy CO_2 Sequestration Pilot Projects

Regional Organization	Project Name	DOE Funding Status	Tons per Year	Duration Years	Planned Sequestered Tons	Total Cost $MM	CO2 Source	Injection Depth ft
Main Projects - Announced DOE Phase III								
Big Sky	Green River Basin Nugget Saline Reservoir Moxa Arch, Western Wyoming	Proposed	1,000,000	3	3,000,000	$110	Gas plant	12,000
MGSC	Illinois Basin Mt. Simon Saline Reservoir	Approved	365,000	3	1,095,000	$84	ADM ethanol plant	5,500
PCOR	Williston Basin EOR Sequestration; ND	Approved	750,000	6	4,500,000	$300	Existing coal plant	10,000
SWCARB	Raton Basin Entrada Saline Reservoir; SW Colorado	Approved	700,000	4	2,800,000	$81	La Veta gas plant	?
SECARB	Mississippi Tuscaloosa Massive Saline Reservoir; SW Mississippi	Approved	1,000,000	1.5	1,500,000	$94	Jackson Dome	10,000
MRCSP	Cincinnati Arch Mt. Simon Saline Reservoir; Greenville, OH	Proposed	280,000	4	1,120,000	$93	Planned ethanol plt.	3,500
WESTCARB	San Joaquin Basin, CA Saline Formation; Olcese and Vedder Sands	Proposed	250,000	4	1,000,000	$91	New 49 MW plant	9,000
Other Proposed DOE Pilot Projects								
SWCARB	Green River Basin Entrada	Proposed	100,000	1	100,000		Pacificorp power plt.	7,000
SECARB	"Athropogenic " Test in Tuscaloosa Massive Saline Reservoir	Proposed	250,000	4	1,000,000			
FutureGen Project	Matoon, IL Location of FutureGen	Selected	2,000,000	20+	50,000,000	$1,500	IGCC plant	