BUILDING THE COSTS CURVES FOR CO_2 STORAGE: NORTH AMERICA

Report Number 2005/3
February 2005

BUILDING THE COST CURVE FOR CO_2 STORAGE: NORTH AMERICAN SECTOR

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) has been systematically evaluating the cost and potential for reducing emissions of greenhouse gases arising from anthropogenic activities, especially the use of fossil fuels. To allow the different mitigation options under consideration to be compared IEA GHG has developed a series of mitigation cost curves which show the potential capacity for CO_2 reduction as a function of the cost. One area of particular focus for IEA GHG's activities has been CO_2 capture and storage. However, IEA GHG does not have mitigation cost-curves for most of the options for CO_2 capture and storage. It was, therefore, agreed at the 20th ExCo meeting (London, UK) that, in a series of studies, the cost curve data would be assembled for all of the potential storage options on a common basis. It was further agreed that the best approach to develop this cost information was to co-operate with regional research activities that were undertaking similar activities.

IEA GHG has now embarked on a programme of work to derive the regional costs of CO_2 storage. To begin the process of developing the costs for geological storage of CO_2 an initial baseline study was completed. The baseline study reviewed the major sources of anthropogenic CO_2, and developed a global database of CO_2 emission sources detailing quantities and locations. This data base contains details of over 14 000 large emission point sources from the power and industry sectors[1]. Following on from the baseline study two regional studies have now commenced, one in Europe[2] and one in North America. The regional information developed in these studies, along with data on the costs of capture and transmission[3], can then be combined to allow future assessments of the comparative costs between CO_2 capture and storage and other mitigation options, such as renewable fuels[4] to be undertaken.

This report reviews the development of a CO_2 storage cost curve for North America, which covers on-shore USA and Canada. The study has been carried out by Battelle, USA in co-operation with the Alberta Energy and Utilities Board, Canada.

Results and Discussion

The following aspects are discussed in this report:

- Study scope and methodology,
- Point source emissions,
- Geological storage capacity in candidate reservoirs in North America,
- Costs for CO_2 storage,
- Proximity of emission sources to storage opportunities and related transmission issues,
- Impact of transmission requirements on storage costs in North America.

[1] IEA Greenhouse Gas R&D Programme report no. PH4/9, Building the cost curves for CO_2 storage, Part 1: Sources of CO_2, July 2002

[2] IEA Greenhouse Gas R&D Programme report no. 2005/2, Building the cost curves for CO_2 storage: European Sector, March 2005.

[3] The costs of CO_2 capture will be compiled in separate studies and then combined with the transmission and storage costs at a later date.

[4] A comparative assessment study between CO_2 capture and storage and some renewable options was agreed upon by members at the 24th ExCo meeting, Paris France.

Study scope and methodology

The study has assessed geological storage opportunities both in on-shore USA and Canada. Off-shore storage opportunities in the USA were not considered because it was felt that currently there was insufficient data to include the offshore storage potential in this study and that given the large capacity of on-shore formations calls into question whether these off-shore formations would be used in the near to midterm. The Canadian component concentrated on the Western Canadian Sedimentary Basin[5] where the main storage potential for Canada is considered to exist.

The CO_2 storage options considered in the study included:

- Storage in depleted/disused oil and gas fields,
- Enhanced Oil Recovery (EOR) combined with CO_2 storage,
- Enhanced coal bed methane recovery (ECBM) combined with CO_2 storage,
- Storage in deep saline aquifers (open and closed structures).

These storage options are considered by IEA GHG to be the most realistic storage options. More novel opportunities such as storage in basalt formations and black shale formations that are currently being researched in the United States were not included in the study.

The cost curves for each storage option were developed by compiling data on geological reservoirs for CO_2 storage and determining the technical storage capacity of these reservoirs. These data, along with the baseline study data on CO_2 sources, were then analyzed within a purpose-built techno-economic model based upon geographic information system (GIS) technology. The mapping capability of the GIS allowed the presentation of the data base information at both regional and continental scales. The computational portion of the model calculated the distance between each source and accessible candidate storage reservoir and compared characteristics such as CO_2 flow rate, remaining storage capacity, depth, and other injection parameters, to estimate the cost for CO_2 transmission and storage for each source and reservoir pair.

Point source emissions

A key activity of the study was to review and update as necessary the USA and Canadian data sets on large point source emissions of CO_2 contained within IEA GHGs data base on global CO_2 emissions[1]. North America has the highest number of stationary CO_2 point sources in the world. For Canada and the United States, this original dataset contained some 5 240 entries, with a total of 4.6 $GtCO_2$ of annual emissions. The dataset was updated as follows:

- The original gas processing data for Canada was completely replaced with a new dataset provided by the Alberta Energy and Utilities Board (AEUB) for gas processing facilities located within the Western Canadian Sedimentary Basin. This dataset was deemed to be considerably more credible, and as a result, the original set of 937 records was replaced with a set of 24 large facilities each emitting more than 100 $ktCO_2$/yr, drastically reducing total CO_2 emissions for the sector.
- The AEUB dataset also provided new and updated source data (including location, annual CO_2 emissions, and concentration) for a number of other industrial facilities located within Western Canada, including power plants, refineries, cement kilns, ethanol production facilities, and oil sands operations,
- For the USA, the power plant data were completely updated with year 2000 reported data from the US EPA at the plant level, and ethanol production plants were added.

Unfortunately, updated data for the gas processing sector similar to that available in Canada could not be located for the USA. However, a similar reduction in gas processing emissions might be expected

[5] The Western Canadian Sedimentary Basin comprises Alberta, Saskatchewan and parts of British Columbia and Manitoba

for select regions of the USA, as compared to the estimates provided in the current IEA GHG dataset which are based on the assumption of a constant CO_2 content for all USA gas fields.

After reconciliation of the emissions data set, 2 082 large anthropogenic CO_2 point sources with annual emissions of at least 100 000 tonnes were identified for analysis in the study. In total, these plants emit nearly 4 $GtCO_2$ per year. The geographical distribution of these emission sources is shown in Figure 1.

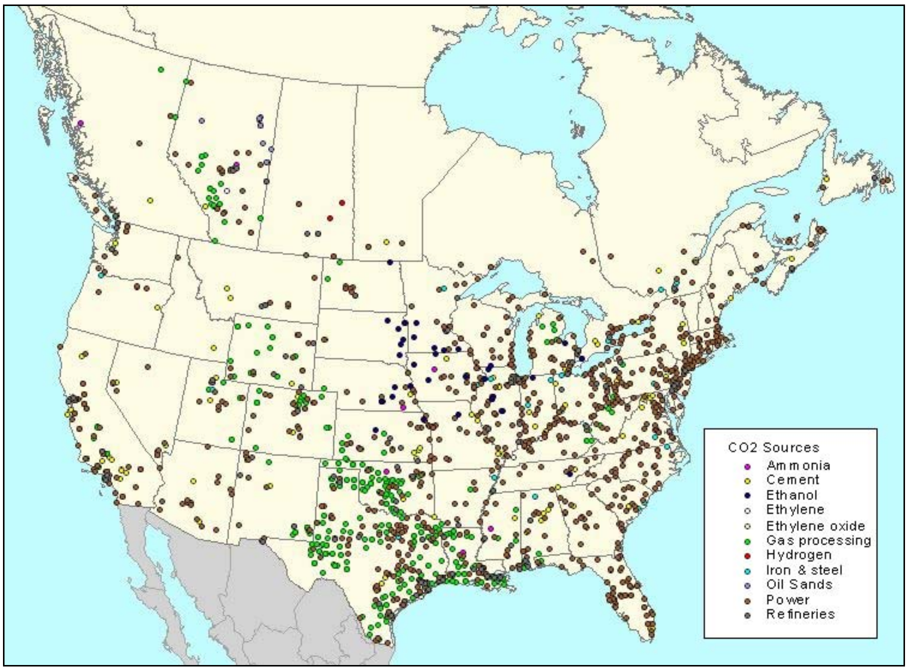

Figure 1. Distribution of Large CO_2 Emission Point Sources in North America

Ninety percent of the large emission point sources are located in the USA and only 10% in Canada. Interestingly, the study revealed that over 75% of the region's CO_2 emissions from large emission point sources are attributable to the 500 largest CO_2-emitting sources (See Figure 2 below).

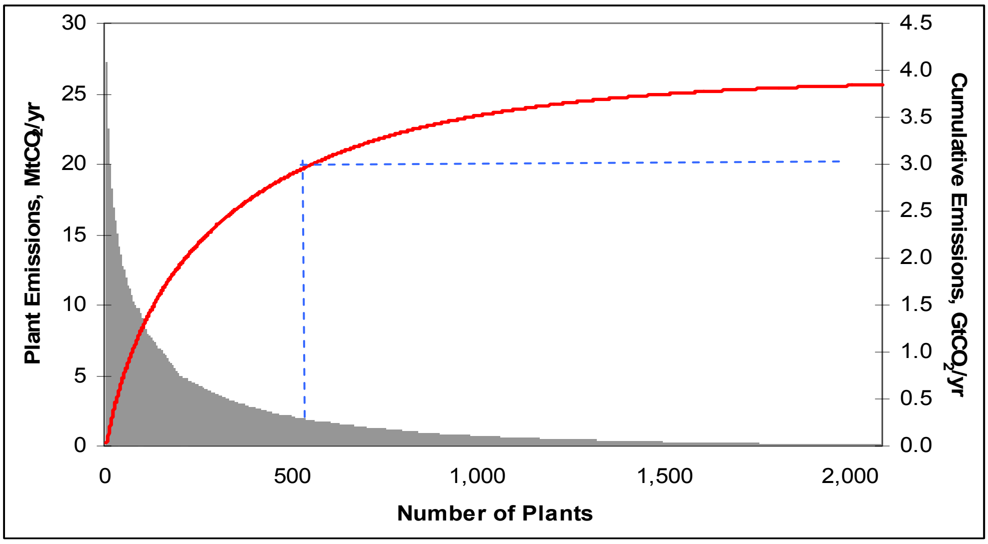

Figure 2. Histogram of Large North American CO_2 Sources (bars) and Cumulative Emissions from these Large CO_2 Point Sources (red line)

Geological storage capacity in candidate reservoirs in North America

This study identified 326 onshore candidate geologic reservoirs, each capable of storing at least 1 $MtCO_2$, with a combined storage capacity on the order of 3 800 $GtCO_2$. The geographical distribution of the candidate geologic CO_2 reservoirs considered in this analysis is shown in Figure 3 overleaf. The CO_2 storage capacity[6] is comprised of 3 700 $GtCO_2$ of storage capacity in deep saline formations (DSF), 65 $GtCO_2$ of capacity in deep unmineable coal seams, 40 $GtCO_2$ of capacity in depleted gas fields, and 12 $GtCO_2$ of CO_2 storage capacities in depleted oil fields with potential for enhanced oil recovery (EOR).

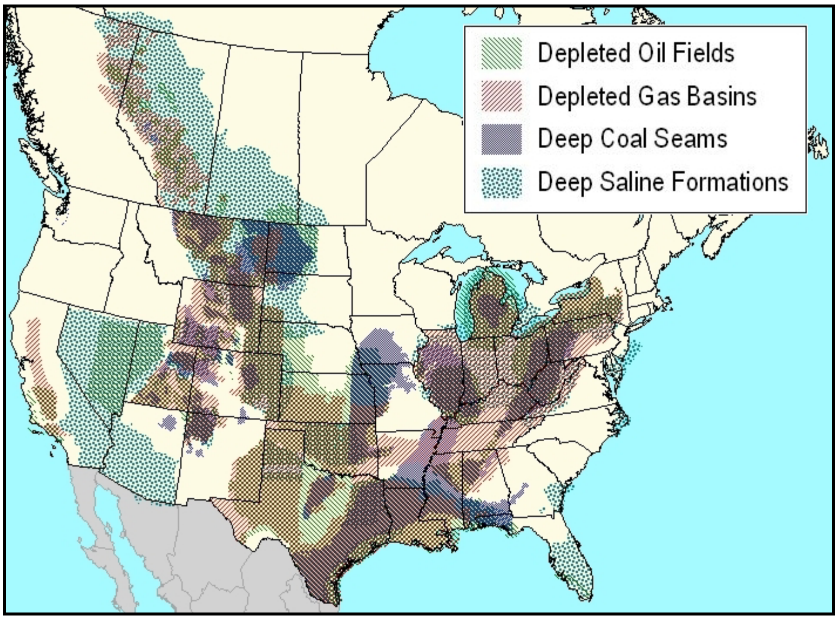

Figure 3. Potential Geologic CO_2 Storage Reservoirs in North America

Costs for CO_2 storage

Costs for CO_2 storage in the different geological storage formations in North America are summarised in Table 1.

Table 1. Summary of Storage Costs for Different Geological Formations

Storage Formation Class	Storage Cost Range $/t CO_2	Mean Storage Cost $/t CO_2
Deep saline aquifers	12 to 15	12.5
Depleted gas fields	11 to 13	12.5
Depleted oil fields	-13 to 37	16.6
CO_2-ECBM	-7 to 30	9.5
All classes	-13 to 37	12.5

Costs for storage alone in individual geological formations, such as deep saline formations and oil and gas reservoirs within North America range from approximately -\$13/t CO_2 to \$37/t CO_2. The costs for storage in depleted oil and gas fields are comparable to those developed in an earlier study by IEA

[6] Details of the methodology used in the storage capacity calculations in this study are given in the main report. It should be noted that, although a similar approach was adopted for capacity estimates in USA and Canada, the level of detail differed in some cases. A higher level of data resolution was available for the Canadian oil and gas pools which enabled capacity estimates to be performed at the reservoir scale, rather than the basin level scale as was required by the available USA data.

GHG[7]. Mean storage costs over all formations (weighted by storage capacity) are roughly \$12/t CO_2. Costs for storage in CO_2-ECBM schemes show a lower average storage cost than for the other three storage options, while a number of depleted oil field based storage opportunities also exhibited lower and sometimes significantly lower than average costs. Therefore, from a strictly economic perspective, select North American depleted oil fields may provide the most attractive near-term storage options, while the lower average storage cost and large capacity (40 Gt) may make CO_2-ECBM overall a potentially more attractive option for many parts of the region. However, the enormous capacity (3 700 Gt) and wide geographic distribution of the region's deep saline formations also make them attractive targets for CO_2 storage, and increasingly so as time goes by. In fact, the report demonstrates that because of the high degree of heterogeneity of circumstances all of the region's CO_2 storage reservoir classes are likely to be utilized in the early days of a CO_2 mitigation regime.

Proximity of emission sources to storage opportunities and transmission issues

The geographic distribution of the 500 largest sources is shown in Figure 4 overleaf, overlain against the set of candidate geologic storage reservoirs in North America.

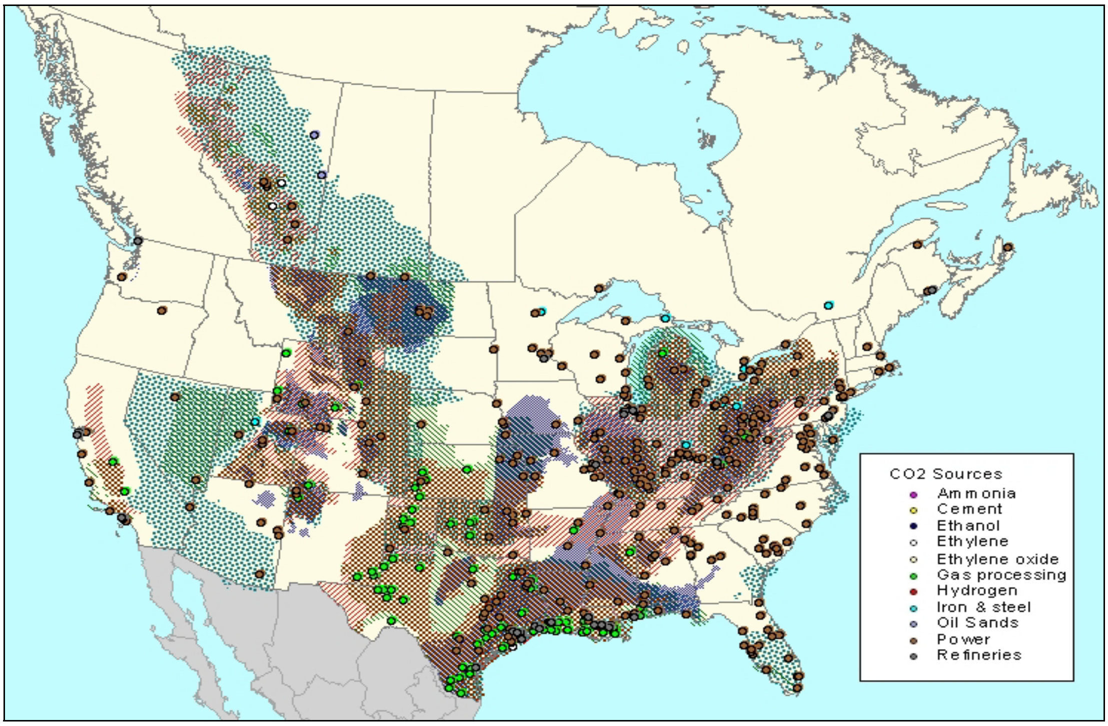

Figure 4. Overlay of the 500 Largest CO_2 Point Sources with Candidate Geologic Storage Reservoirs

The study has identified that most of the 500 very large CO_2 point sources are located within close proximity to a potential storage reservoir. 392 of them (61% of the region's total large point source CO_2 emissions) are located right above a candidate geologic storage formation, and 478 (73% of the region's total large point source CO_2 emissions) have at least one potential geologic storage option within just 161 km (100 miles). Thus a significant reduction in the region's CO_2 emissions is possible by focusing on this subset of the region's CO_2 point sources. With the close proximity of the point sources to the storage reservoirs it was considered to be unlikely that neither long distance pipelines will be required or extensive CO_2 pipeline networks may need to be developed in North America.

[7] IEA Greenhouse Gas R&D Programme report no. PH3/22, Barriers to the implementation of CO_2 capture and storage: (1) Storage in disused oil and gas fields , February 2000

Impact of transmission requirements on storage costs in North America

The impact of CO_2 transmission needs on storage costs was modelled assuming a 161-km (100-mile) radius from the point source to the storage option, and that each potential storage formation must be able to store 10 years' worth of a source's captured CO_2. Combined transmission and storage cost curves were then developed firstly for a reference case and then to assess the sensitivity of a number of key factors[8]. The annual costs curve generated for the modelled reference case is given in Figure 5.

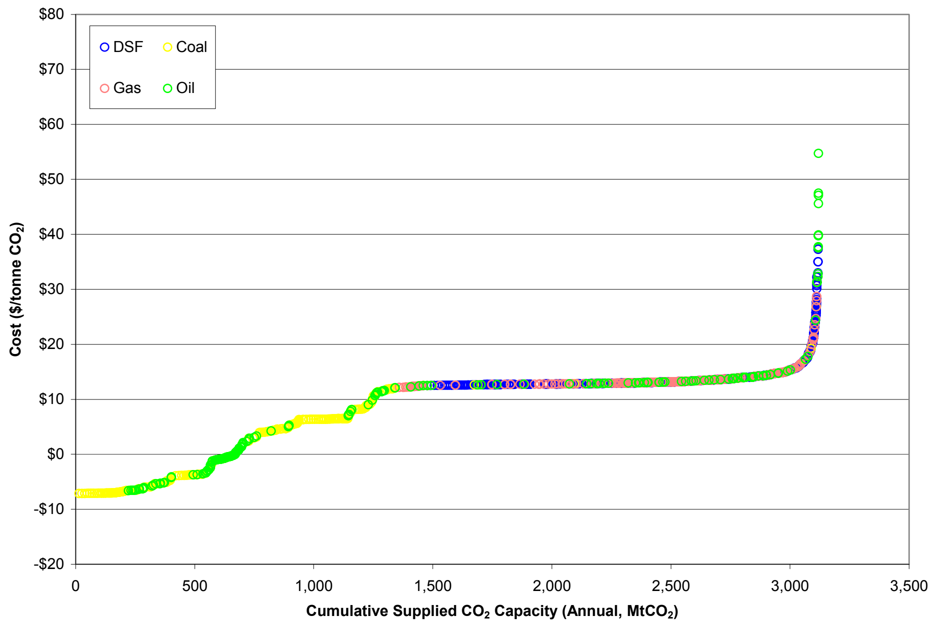

Figure 5. CO_2 Storage Supply Curve for North America for the Reference Case

In the Reference Case, 93% of the large point sources can be connected to at least one potential storage reservoir within a 161 km (100-mile) radius. Annually, 3 121 $MtCO_2$ of captured CO_2 can gain access to a storage reservoir. The total cost for CO_2 transport and storage ranges from -$7.13 to $54.70/tonne CO_2. The total length of pipeline needed to distribute the CO_2 from the sources to their selected storage reservoirs, as calculated by the model, amounts to some 127 000 km (79 000 miles) of dedicated CO_2 pipelines, or an average of about 70 km (41 miles) per source-reservoir pair. In this first modelled ten year period, storage in enhanced recovery operations (CO_2-ECBM and CO_2-EOR) account for 45% of all supplied capacity, with the remainder coming in the form of DSF and depleted gas reservoirs, with costs of around $12/tonne CO_2. In subsequent time periods, the CO_2 storage capacity in North America is likely to be increasingly supplied by deep saline formations as the low-cost fields benefiting from enhanced hydrocarbon recovery are filled due to the high demand placed upon them by large concentrations of CO_2 point sources.

[8] Sensitivities examined included maximum distance from source to reservoir, oil and natural gas prices, and minimum storage capacity commitment, among others.

Expert Group Comments

The draft report on the study was sent to a panel of expert reviewers and to a number of IEA GHG's members who had expressed interest in reviewing it. The reviewers reported no major issues with the study's methodology or presentation of findings, and requested no substantive changes.

Major Conclusions

A significant geological storage capacity for CO_2 (3 800 $GtCO_2$) has been identified within the USA and Canada. Annual emissions of CO_2 from large emission point sources in 2000 within this region equated to nearly 4 $GtCO_2$. Therefore, there is sufficient storage capacity within North America to store all of the year 2000 fossil fuel-related CO_2 emissions for nearly 1000 years. Even allowing for continued economic growth, the deployment of CO_2 capture and storage technologies in North America should not be constrained by a lack of potential storage capacity.

In total, over 2 000 large emission point sources were identified by the study. However, 500 of these plants represent 75% of the total annual emissions of CO_2. Concentrating early CO_2 capture and storage activities on these emission sources would make a significant impact on the region's CO_2 emissions.

Most of the storage capacity identified is in deep saline formations. These reservoirs tend to be the least-well explored and hence warrant an intensive research effort to determine their true potential as storage reservoirs. It is noted that research on deep saline formations is a key focus area of the US Carbon Storage Programme and that a number of active CO_2 injection tests are now underway or planned in the USA to develop knowledge on the potential of these reservoirs.

In North America, many point sources lie either adjacent to or within 161 km (100 miles) of the potential storage opportunities, implying that extensive long distance pipelines for CO_2 transport may not be needed nor does there appear to be significant economic savings to be had from the operation of common trunk lines.

The overall costs for CO_2 storage in the USA were modeled to be effectively capped at about \$12-15/tCO_2, with important yet limited resource available below \$0/t CO_2.

Recommendations

The North American study has highlighted a potential issue with the gas processing sector CO_2 emissions data in the global IEA GHG source data base. There is still a large number of emission point sources (>2,000) within the global data base which, based on our experience from Canada in this study, might significantly overestimate the CO_2 emissions from this sector. A similar comment was raised on the study results during expert review process on the IPCC Special Report on Capture and Storage. It would be in IEA GHG's interest from both a technical perspective and to improve the quality of our data set to rationalize the gas processing data. A new small study could be appropriate to review and update the gas processing sector data.

PNWD-3471

A CO_2 Storage Supply Curve for North America

RT Dahowski[a], JJ Dooley[b], CL Davidson[a], S Bachu[c], and N Gupta[d]

December 2004

[a]Battelle – Pacific Northwest Division
902 Battelle Boulevard
Richland, Washington 99352. USA

[b]Battelle, Joint Global Change Research Institute
8400 Baltimore Ave, Suite 201
College Park, Maryland 20740. USA

[c]Alberta Energy and Utilities Board
640 - 5 Avenue SW
Calgary, Alberta T2P 3G4. Canada

[d]Battelle
505 King Avenue
Columbus, Ohio 43201. USA

Prepared for
IEA Greenhouse Gas R&D Programme
Stoke Orchard, Cheltenham
Gloucestershire, United Kingdom
under Contract IEA/CON/02/82

LEGAL NOTICE

This report was prepared by Battelle Memorial Institute (Battelle) as an account of sponsored research activities. Neither Client nor Battelle nor any person acting on behalf of either:

MAKES ANY WARRANTY OR REPRESENTATION, EXPRESS OR IMPLIED, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, process, or composition disclosed in this report may not infringe privately owned rights; or

Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, process, or composition disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by Battelle. The views and opinions of authors expressed herein do not necessarily state or reflect those of Battelle.

Abstract

This report presents the results of a two-year research project undertaken by researchers at Battelle and the Alberta Energy and Utilities Board to better understand the deployment potential for carbon dioxide (CO_2) capture and storage (CCS) systems in North America. More than 300 onshore candidate geologic reservoirs in the United States and Canada were examined in the scope of the study. These reservoirs represent a large and variably distributed North American CO_2 storage capacity of at least 3,800 gigatonnes of carbon dioxide ($GtCO_2$). Characteristics of 2,082 anthropogenic CO_2 point sources in North America, each with annual emissions greater than 100,000 tonnes of CO_2, are also presented. By computing a series of pairwise cost-minimizing decisions for these CO_2 sources and potential geologic storage reservoirs, a CO_2 storage cost curve for North America was calculated. The cost curve incorporates the cost of transporting CO_2 from each source to a selected storage reservoir, the cost of injecting it into the underground formation, and any offsetting revenue associated with resulting enhanced hydrocarbon recovery, yielding a classic, positively sloping supply curve. The results suggest that in Canada and the United States, the long term cost of CO_2 transport and storage is effectively capped at approximately $12-15 per tonne CO_2. Some individual sources will face higher or lower costs for transporting and storing their CO_2 in geologic formations, but at the macroeconomic level for these two nations, there is little indication that CO_2 transport and storage costs will escalate much beyond this level for the balance of this century – and perhaps well into the next – due to the widespread availability of significant storage capacity in North America. The study also explores cost sensitivities associated with changes in oil and gas prices, the maximum transport distance between source and reservoir, and changes in the infrastructure costs for storage in value-added reservoirs.

KEY WORDS: carbon dioxide capture and storage; geologic storage of CO_2; carbon management; climate change; North America; Canada; United States.

Executive Summary

This report presents the results of a two-year research project undertaken by researchers at Battelle and the Alberta Energy and Utilities Board to better understand the deployment potential for carbon dioxide (CO_2) capture and storage (CCS) systems in the United States and Canada. The project has focused on three primary objectives: (1) the collection and analysis of considerable data on CO_2 point sources and candidate geologic CO_2 storage reservoirs within North America; (2) the development of a CO_2 storage cost curve methodology that is rigorous and suitable for use in this and other studies; and (3) the computation of CO_2 storage supply cost curves for North America. This report presents the results of this research.

The Potential Market for CCS Technologies in North America
While much of the technical literature rightly focuses on the deployment of CCS technologies within the electric power sector, as this is likely the largest potential market for this class of technologies, the true market for CCS technologies extends far beyond this one industry. Within North America (defined herein as Canada and the 48 contiguous United States), this study identified 2,082 anthropogenic CO_2 point sources, each with annual emissions greater than 100,000 tonnes of CO_2. These 2,082 CO_2 point sources include: 1,156 fossil fuel-fired power plants (accounting for 66% of these point sources' total CO_2 emissions), 444 natural gas processing facilities (22%), 146 refineries (5%), 123 cement kilns (2%), 53 iron and steel plants (2%), 43 ethylene plants (2%), 9 oil sands facilities (1%), 40 hydrogen facilities (<1%), 25 ammonia plants (<1%), 35 ethanol plants (<1%), and 8 ethylene oxide plants (<1%). Together these sources emit nearly 4 $GtCO_2$ annually, with the majority (90% of them, accounting for 3.6 $GtCO_2$/yr) being located within the United States. The geographic and sectoral distribution of these 2,082 point sources is shown in Figure ES1.

The North American Geologic CO_2 Storage Resource
This study also sought to better describe the potential geologic CO_2 storage resource within North America and thus identified 326 onshore candidate geologic reservoirs, each capable of storing at least 1 $MtCO_2$. The combined storage capacity of these reservoirs is approximately 3,800 $GtCO_2$. Theoretically, this represents enough capacity to store the CO_2 emissions from these point sources for more than 600 years. Thus, even if this study's capacity estimates are optimistic, and even allowing for continued growth in emissions, the deployment of CCS technologies should not be constrained in these nations by a lack of potential storage capacity. This potential CO_2 storage capacity includes 3,700 $GtCO_2$ of capacity in deep saline-filled sedimentary formations (DSF), 65 $GtCO_2$ of capacity in deep unmineable coal seams, 40 $GtCO_2$ of capacity in depleted gas fields, and 12 $GtCO_2$ of storage capacity in depleted oil fields with potential for enhanced oil recovery (EOR). This study did not examine the additional CO_2 storage potential of deep saline-filled basalt formations, deep black shale formations, off-shore reservoirs, or other candidate geologic formations that have been discussed in the technical literature. Figure ES2 shows the spatial distribution of the candidate geologic CO_2 reservoirs considered in this analysis.

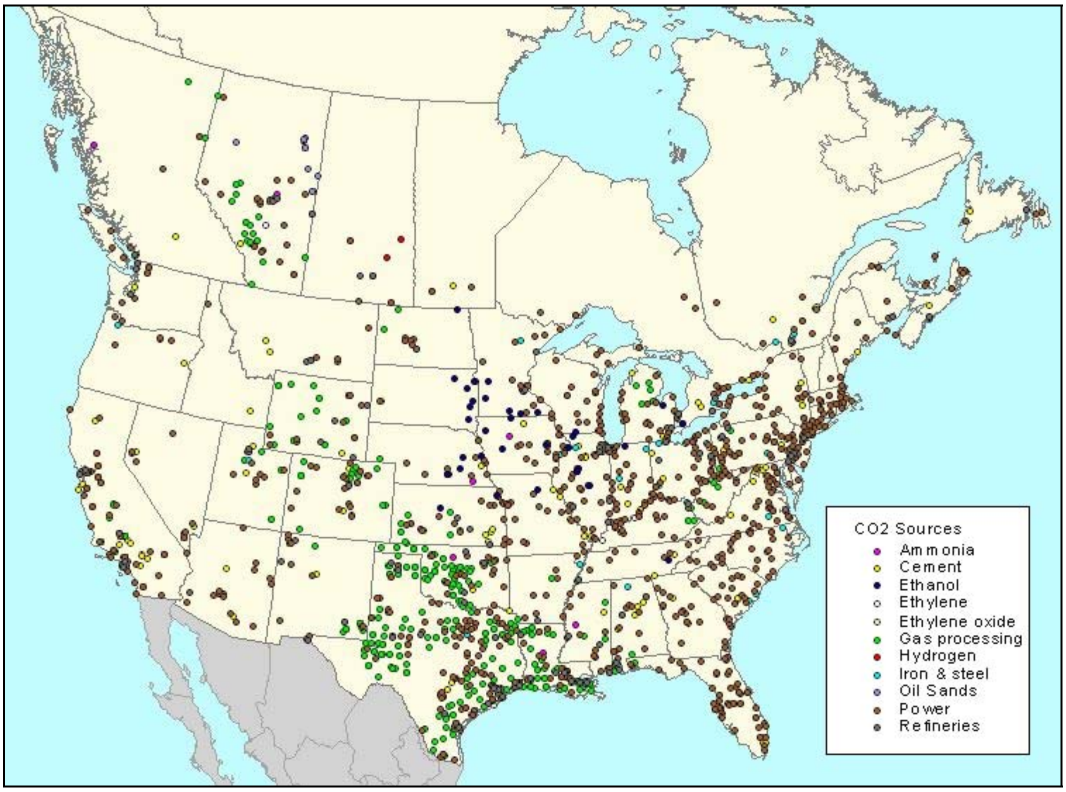

Figure ES1. Large CO_2 Point Sources in North America

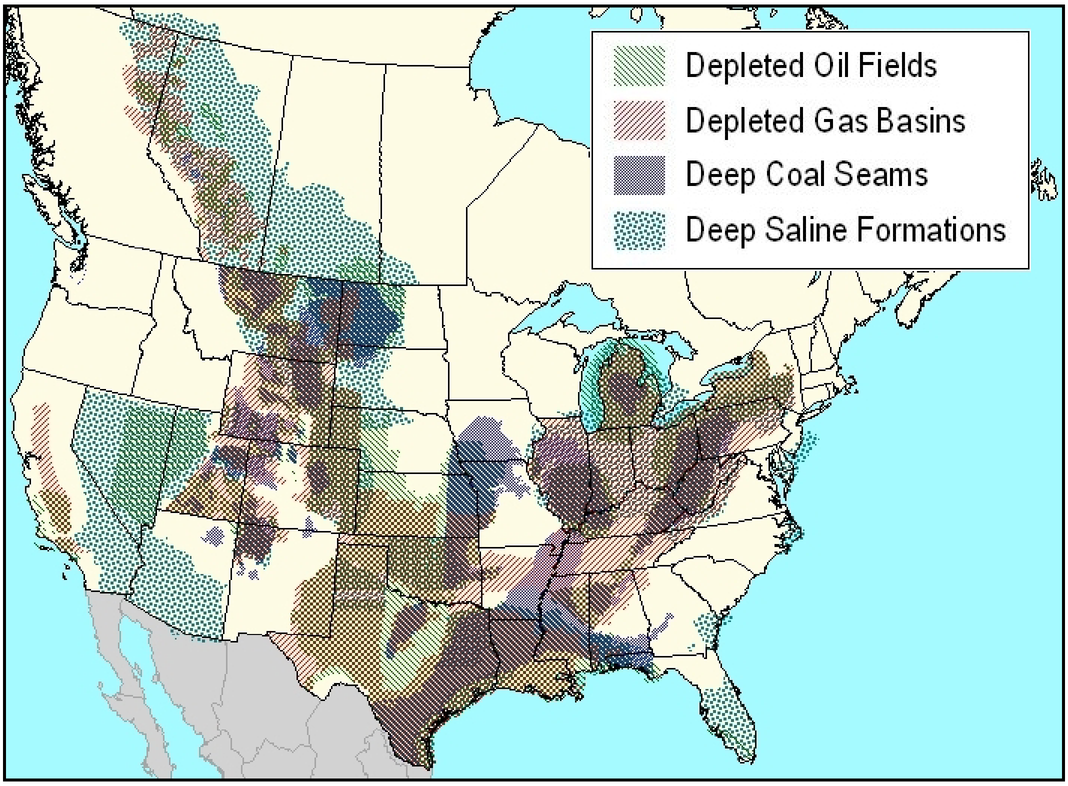

Figure ES2. Potential Geologic CO_2 Storage Reservoirs in North America

The Cost of North American Storage Capacity: Lifetime Storage Supply Curve
The aggregate Lifetime Storage Supply Curve (Figure ES3) shows storage costs as a function of cumulative total capacity and best represents what the long-term cost of CO_2 storage might be within North America. This curve, based on the detailed analysis presented in Chapters 5 and 6, suggests that over time, the vast majority of CO_2 storage capacity will be supplied at a storage cost of between \$12 and \$15 per tonne CO_2. In fact, 98% of the more than 3,800 gigatonnes of potential capacity shown on this Lifetime Storage Supply Curve falls within this \$12 to \$15 range. This leaves a comparatively small but nonetheless important amount of capacity available at storage costs both above and below this range. While this curve does not include transport costs, a large fraction of North American CO_2 point sources are conveniently located near or atop the formations that provide a large, consistently priced supply of storage capacity. As such, over the long term, costs associated with storage of CO_2 will tend toward this \$12 to \$15/tonne CO_2 threshold price, and as with the decadal cost evolution presented in Section 5.3, over time the trend will be to shift an ever increasing portion of the CO_2 storage load to deep saline formations.

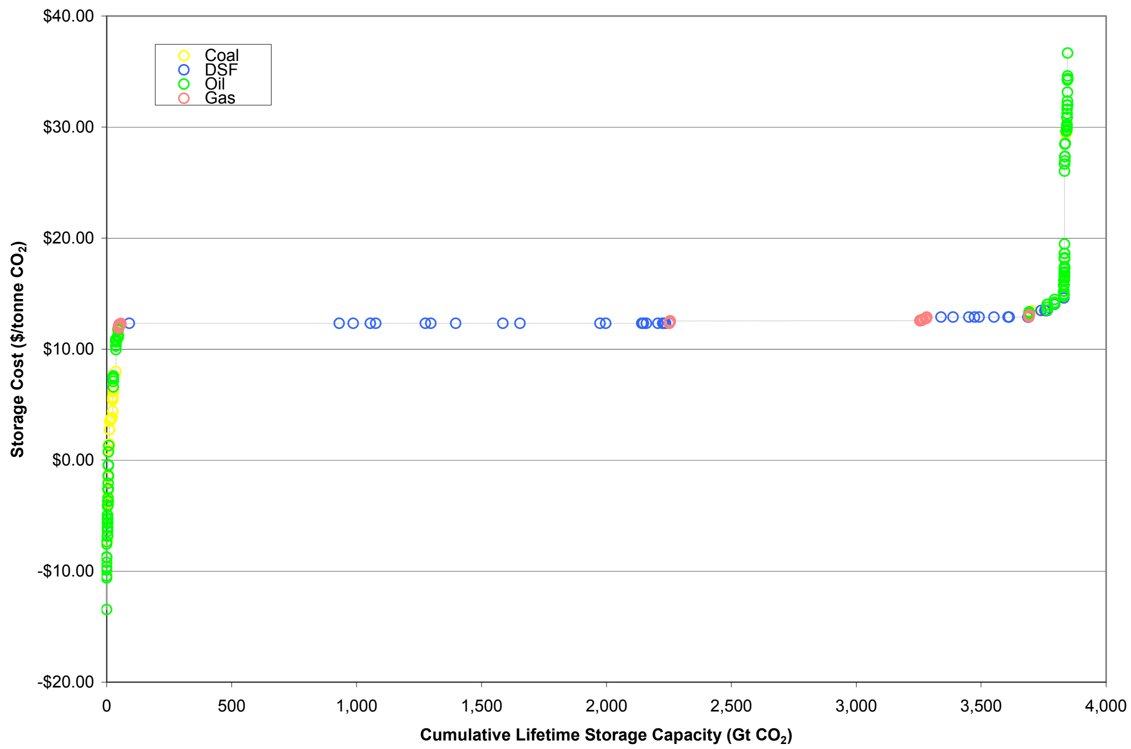

Figure ES3. Lifetime Storage Cost Curve for North America by Formation Type

Supply and Demand: Modeling the CCS Market

A methodology was devised to explore how market-based demand for CO_2 storage capacity might develop across North America. This methodology was used to examine the market interplay between the 2,082 large North American point sources and the large but finite 3,800 $GtCO_2$ of identified North American storage capacity. This market-based dynamic between sources *seeking* storage capacity and candidate CO_2 storage reservoirs *offering* storage capacity was represented by an engineering and economic model that enables pairwise cost-minimizing comparisons for these CO_2 sources and potential geologic CO_2 storage reservoirs. This model explicitly represents the cost of transporting CO_2 from the source (post-compression) to a selected storage reservoir, the cost of injecting it into the underground reservoir, and any offsetting revenue associated with resulting enhanced hydrocarbon recovery. Costs associated with CO_2 capture were intentionally left outside the scope of this study, to allow for a clear focus on the storage side of CCS economics. The model employed here also includes rules to ensure that a reservoir's capacity is not oversubscribed by determining which sources are able to access a given reservoir's storage capacity and in what order this access is granted, and to attempt to reflect real world considerations that would likely shape decisions regarding deployment of CCS infrastructure.

From the tens of thousands of potential source/reservoir combinations (i.e., many point sources have access to more than one potential reservoir), the model selects the minimum available cost pair for each source. A CO_2 Storage Supply Curve is created by plotting all selected cost pairs. The majority of this report centers on the construction of a central Reference Case CO_2 Storage Supply Curve for North America and various sensitivities on key parameters such as: high/low oil and natural gas prices; the maximum allowed distance between source and reservoir; differing assumptions on the additional infrastructure costs required for CO_2 storage in value-added reservoirs; and differing assumptions on the minimum storage capacity commitment that private sector firms would need to secure in order to inject CO_2 in a given formation. The impact of "reservoir filling" is examined over the course of a 30-40 year period, as it relates to the selection of reservoirs and the shifting makeup of supplied storage capacity and the cost for CO_2 storage.

Major Conclusions

The United States and Canada have a potential geologic CO_2 storage resource of at least 3,800 $GtCO_2$. At an aggregate level this capacity should be capable of meeting demand for CO_2 storage for the remainder of the 21st century and likely for a considerable period thereafter. However, CO_2 will be captured and stored at the local level, and it is the local conditions and resources of a region that will define the demand for storage capacity and the resulting competition for access to its geologic reservoirs.

- Within North America, the majority of CO_2 emissions from large stationary CO_2 point sources come from a relatively small number of large, low-purity CO_2 point sources. Over 75% of the region's CO_2 emissions from large point sources are attributable to the 500 largest CO_2-emitting sources. Most of these very large CO_2 point sources are located within close proximity to a potential storage reservoir. 392 of them (representing 61% of the region's total large point source CO_2 emissions) are located above a candidate geologic storage reservoir, and 478 (representing 73% of the region's total large point source CO_2 emissions) have at least one potential geologic storage option within just 100 miles (161 km). This suggests that CCS has the potential to deliver significant emissions reductions by focusing efforts on the largest sources consisting predominantly of large fossil fuel-fired power plants, gas processing facilities, iron and steel mills, and petroleum refineries.

- Potential costs for CO_2 storage cover a wide range as CO_2 reservoirs and the large CO_2 point sources that are candidates to employ CCS are neither homogeneous nor evenly distributed across North America. This report documents costs for CO_2 storage (i.e., exclusive of the cost of capture, compression, and dehydration) that span -$7 to $55/tonne CO_2 for the Reference Case, and from -$64 to $71/tonne CO_2 across the various sensitivities (e.g., high oil and gas prices) explored here.

- While the range in potential storage costs can be large, the vast majority of CO_2 storage capacity in North America's geologic reservoirs should be available at or below $12 to $15/tonne CO_2. Thus, as a general guideline, a storage cost of $15/tonne CO_2 might represent an upper bound on what is likely to be paid for the balance of this century – and perhaps well into the next – for those sources seeking storage capacity in North America.

- There appears to be a significant quantity of CO_2 storage capacity that can be accessed for less than $0/tonne CO_2 (i.e., the revenue from produced oil and natural gas from CO_2 storage in some depleted oil fields and deep unmineable coalbeds is sufficient to offset the cost of building and maintaining the needed CO_2 transport and injection infrastructure and facilities). Depending upon assumptions about the price of oil and natural gas and on the extent – and therefore the cost – of needed hydrocarbon recovery infrastructures, there could be between a few hundred million tonnes to tens of gigatonnes of negative cost CO_2 storage capacity available in North America. However, once the cost of capture is factored in, the deployment of CCS technologies will predominantly be a positive cost activity; i.e., CCS technologies would not deploy on a large scale in North America without an explicit policy mechanism designed to significantly reduce CO_2 emissions over the long term.

- To the extent that there are low and even negative cost storage opportunities, this "low hanging fruit" is likely to be consumed quickly (within a decade or two) once large-scale use of CCS commences in North America. In particular, because of the high concentration and large number of CO_2 point sources in an area like the Ohio River Valley, low-cost storage options (i.e., depleted oil fields and unmineable coal seams offering value-added hydrocarbon recovery) could be consumed early on. Fortunately, there are large deep saline formations in this region and over the long term their abundant storage capacity should be able to satisfy the CO_2 storage needs of this region. On the other hand, the value-added reservoirs in western Canada, the Rocky Mountains and Great Plains region of the United States, as well as other select areas in the western U.S., have fewer large CO_2 sources nearby to demand their storage capacity and therefore these regions have the potential to see low-cost storage opportunities persist for longer periods of time.

- Higher prices for oil and natural gas will likely have a modest impact on the cost of CO_2 storage for the North American economy as a whole. However, fluctuations in the price of these energy commodities could have a large impact on the economics of individual CO_2 storage projects.

- There appears to be relatively little need in North America for the construction of very long CO_2 pipelines to move CO_2 to suitable reservoirs as 77 percent of sources (by volume) sit directly above candidate CO_2 storage reservoirs. Allowing for pipelines of up to 100 miles (161 kilometers) to connect each source to a suitable storage reservoir enables a 25 percent increase (over the 0-mile case) in the volume of CO_2 that is able to access a suitable storage reservoir. Three quarters of this additional supplied storage capacity is due to sources sending their CO_2 to more distant storage options that may benefit from CO_2-driven advanced hydrocarbon recovery.

Future Research Recommendations
This study represents the most comprehensive analysis of CO_2 transport and storage for the North American continent to date. It could serve as a critical resource for national CCS planners and help advance the discussion of CCS deployment. Yet, during the course of this research, several key out-of-scope considerations were revealed, which, if addressed in future work could further refine the discussion as CCS moves closer to deployment. Recommendations for continued research include the following:

- Evaluate how the cost of CO_2 capture from these sources impacts the deployment of CCS systems within North America. In particular, future work should seek to reflect varying costs of capture across these classes of CO_2 point sources (e.g., the cost of capture from an ethanol plant should be less than the cost of capture from an existing pulverized coal plant). Adding the cost of capture would shift the cost curve upward to varying degrees and would paint a more detailed picture of which combinations of sources and reservoirs would have relatively low costs (and may therefore be candidates for early CCS adoption) and which source-reservoir pairs would have higher costs.

- Gather more detailed data on geologic reservoirs throughout the United States and Canada, expanding coverage and improving data resolution on existing reservoir types as well as additional reservoir types not considered in this study. CCS-specific reservoir characterization is still in its infancy, and though the best data available were used in this analysis, the technical community has identified improving these data as one of the critical issues that must be addressed to lay a path forward for CCS deployment. New, reservoir-specific characterizations conducted with an eye toward CO_2 storage could significantly impact the economics as presented here.

- Continue to update and improve the CO_2 point source datasets. For North America, it is particularly important to refine data on the locations and CO_2 emissions from natural gas processing facilities, particularly those in the United States, as there is less confidence in the estimates for these sources.

- Pursue the construction of CO_2 supply cost curves similar to those presented here for other regions of the world, and in particular for regions that are growing rapidly (e.g., China and India). In the future, these regions will be among the largest CO_2 emitters, and there is therefore a need to start examining and outlining CCS deployment opportunities for these countries. The knowledge gained by carrying out CO_2 supply cost curve studies in these rapidly growing regions would likely prove invaluable by enabling better-informed decisions about CCS infrastructure to be incorporated from the earliest planning stages for new long-lived capital stock such as power plants.

Acronyms/Abbreviations

BBL – Barrel of Oil

CCS – Carbon Dioxide Capture and Storage

CO_2 – Carbon Dioxide

DSF – Deep Saline Formation

ECBM – Enhanced Coalbed Methane

EOR – Enhanced Oil Recovery

EUR – Estimated Ultimate Recovery

GASIS – Gas Information System

GJ – Gigajoule or 1,000,000,000 joules

GOR – Gas-to-oil Ratio

$GtCO_2$ – 10^9 tonnes (gigatonne) of CO_2 which is equal to 10^{15} grams of CO_2 (a petagram)

HCPV – Hydrocarbon Pore Volume

IEA GHG – International Energy Agency's Greenhouse Gas R&D Programme

$ktCO_2$ – 10^3 tonnes (kilotonne) of CO_2

mmcf – Million Cubic Feet

MMP – Minimum Miscibility Pressure

$MtCO_2$ – 10^6 tonnes (megatonne) of CO_2

NOGA – National Oil and Gas Assessment

OGIP – Original Gas in Place

OOIP – Original Oil in Place

TDS – Total Dissolved Solids

URR – Ultimate Recoverable Reserves

U.S. – United States

USGS – United States Geological Survey

WAG – Water-alternating with Gas

WGR/WOR – Water-to-gas Ratio/Water-to-oil Ratio

Contents

Figures

Tables

1.0 Introduction

Ever since the publication of Marchetti's (1977) first paper on the idea of permanently storing CO_2 as a means for addressing climate change, there has been growing interest in the idea of using the oceans (Marchetti's focus) as well as deep geologic formations (the focus of this report) as a means of permanently isolating large volumes of CO_2 from the atmosphere. Research in this field – now commonly known as carbon dioxide capture and storage (CCS) – encompasses a broad array of topics from advanced power systems such as coal-fired integrated gasification combined cycle (IGCC) power plants that facilitate more efficient CO_2 capture, new and improved methods for CO_2 purification, potential development of CO_2 pipeline networks, and effects of impure CO_2 streams with regard to infrastructure requirements, to name just a few. Priority issues related to CO_2 storage in the subsurface include developing an understanding of the storage capacity, assessment of hydrogeologic, geochemical, geomechanical, and regulatory aspects with the ultimate objective of demonstrating the safety and technical viability of these concepts and winning public acceptance of CO_2 storage as a means for mitigating climate change concerns.

Interest in this field has accelerated over the last decade and there are now a small number of significant CCS field projects underway with additional projects ready to be initiated in the near future. These field projects and numerous laboratory experiments being carried out across the world are helping to refine current knowledge about CCS systems and how their individual components will work in practice. This knowledge will surely prove instrumental in the initial commercial deployment of CCS systems. However, if society is to address climate change in a manner that approaches the stated ultimate objective of the United Nations Framework Convention on Climate Change (UNFCCC) of the "stabilization of greenhouse-gas concentrations … at a level that would prevent dangerous anthropogenic interference with the climate system,"[1] the challenge confronting those interested in CCS systems becomes one not of deploying a small number of CCS-enabled systems but rather deploying perhaps thousands of these systems over the course of the 21st century.[2] It is this potential large-scale deployment of CCS technologies that is the motivation for this study. That is, while this study sheds light on the market conditions likely to be encountered by the first commercial deployments of CCS units, the objective at the heart of this study is to better understand what the large-scale, long-term economic deployment of CCS-enabled energy and industrial systems across the economies of the United States and Canada might look like.

1.1 The Role of CCS Technologies in Addressing Climate Change

Prior analysis of the global and/or regional deployment of CCS has demonstrated the enormous potential of CCS technologies in addressing climate change. Previous work has shown:

- CCS technologies could play a critical role in addressing climate change with CCS-enabled power plants capturing a very large portion of the electric power generation market in greenhouse gas constrained scenarios (e.g., Riahi et al. 2004).

[1] It is important to note that the United Nations Framework Convention on Climate Change (United Nations, 1992) is silent on what would be a "safe" atmospheric concentration for greenhouse gases and that these levels remain a subject of debate. There is, as of the writing of this report, no scientific consensus on what a safe level would be.
[2] See for example Dooley et al., 2004a which suggests a need to deploy more than 1,000 CCS-enabled electric power plants between 2005 and 2050 for just the U.S. electric power sector in response to a global effort to stabilize at 450ppmv.

- CCS technologies coupled with an efficient emissions trading system could halve the cost of bringing about a stabilized atmospheric concentration of CO_2 (Scott et al. 2004). This represents hundreds of billions of dollars in potential savings compared to the case in which CCS technologies are not allowed to deploy.

- The ability to employ CCS technologies can be a key enabling technology in the development of a climate friendly "hydrogen economy" (see for example, Edmonds et al. 2004 and Hoffert et al. 2002).

- CCS technologies appear to be synergistic with biomass energy technologies holding forth the potential to create energy systems with negative emissions, an option that might prove necessary if a decision were made to attempt stabilization at relatively low concentration levels (Edmonds et al. 2004 and Obersteiner et al. 2002).

These and many other studies strongly suggest that CCS technologies could well play a key if not vital role in helping to fulfill the stabilization goal of the UNFCCC. It is, in some measure, because of studies such as these that speak to the long-term potential of CCS in addressing climate change that CCS technologies are now on the policy agendas of many nations[3] and CCS-related research is now becoming a more prominent aspect of many national energy and climate change mitigation R&D portfolios.

Yet for all the promise and potential of CCS technologies, there are still critical gaps in our knowledge about how this class of technologies will operate in practice. In particular, most global- to regional-scale studies of CCS deployment to date assume a fixed CO_2 transport and storage cost, adopted mainly in response to a lack of data about how CO_2 transport and storage might vary geographically or temporally.[4] While the initial adoption of this kind of an assumption is reasonable, the economic implication is that CO_2 storage reservoirs are infinite, homogeneously distributed around the world, and uniform in terms of quality.[5] This is clearly not the case; in the real world, CO_2 will be captured at a particular point source and stored into a specific reservoir. The point source and the reservoir are unique and will have specific attributes that determine the unique cost of moving CO_2 from that point source to the reservoir and storing the CO_2 within the reservoir. This report describes the first attempt to define these unique transport and storage costs for all large point sources within North America.

---

[3] The recent inception of both the Intergovernmental Panel on Climate Change's Special Report on Carbon Dioxide Capture and Storage and the multinational Carbon Sequestration Leadership Forum are two clear examples of the increasing attention governments are paying to CCS technologies.

[4] Dooley et al. 2004b is a recent study using an integrated assessment model in which this constant price of transport and storage assumption is replaced with a more robust modeling of the depletable resource nature of candidate CO_2 storage reservoirs around the world. Modeling CO_2 storage reservoirs as a depletable resource yields significantly different answers particularly at the national level in terms of how CCS might deploy during this century across the globe.

[5] The implications of the assumption that the cost of transport and storage is constant for all potential source / reservoir pairs and does not change with time is explored further in Dooley et al. 2002.

1.2 Defining "A North American CO_2 Storage Supply Curve"

This report presents a series of "CO_2 Storage Supply Curves" for North America. It is imperative to clearly understand the meaning of these terms before moving on to the presentation of the data collected in this report and discussions of the underlying modeling and analyses.

For the purposes of this study, "North America" is defined as Canada plus the contiguous 48 states of the United States. For candidate geologic storage reservoirs within Canada, the focus is on reservoirs in the Western Canadian Sedimentary Basin, encompassing the entire province of Alberta and areas of British Columbia, Saskatchewan, and Manitoba. Future iterations of this analysis will aim to incorporate data for the CO_2 point sources and, to the extent they exist, candidate geologic storage reservoirs within Alaska, Hawaii, Mexico, and the remainder of Canada.

The term "CO_2 Storage Supply Curve" was specifically adopted by this study in order to stress some key points that readers need to bear in mind when reviewing this report and its results. First, this is a study that is focused on the transport and storage costs of deploying CCS systems. The cost of capture has been specifically and purposefully disregarded in this study. Therefore, the costs presented here represent the cost of moving compressed and dehydrated pipeline-quality CO_2 from the "plant gate" to a suitable injection point above a candidate geologic CO_2 storage reservoir, the cost of injecting CO_2 into the formation (e.g., drilling, completing and maintaining injection wells) and the cost of monitoring the stored CO_2. The cost of CO_2 capture and compression is a major component in the operation of CCS systems and therefore when viewing the results of this analysis, readers must keep in mind that the costs associated with capture would be additional to the costs presented.

1.3 Modeling the Competition for CO_2 Storage Capacity: The Meaning of "Pairwise"

A major theme of this report is that while the United States and Canada are home to very large candidate CO_2 storage reservoirs, these reservoirs are nonetheless finite. As such, it is imperative that these candidate geologic CO_2 storage reservoirs be modeled as a *depletable natural resource*. That is, as the resource is consumed (in this case "filled"), the remaining capacity becomes scarcer and therefore more valuable and costs should rise. Thus with time, all other things being equal, the cost of CO_2 storage should rise as the lowest-cost reservoirs are filled and CCS users find it necessary to transport their CO_2 to either more distant or more costly CO_2 storage reservoirs.

In order to capture this behavior, the underlying analysis computes a series of what will be referred to as "pairwise" cost-of-storage calculations between each CO_2 point source and all of the candidate CO_2 storage reservoirs within a given search radius (e.g., 0, 100, 250 miles). From the large number of potential cost pairs[6] (where a cost pairing represents the mating of a given CO_2 point source with a candidate CO_2 storage reservoir and incorporates the cost of CO_2 transport and injection), the minimum cost is selected for each source. However, since multiple CO_2 point sources are located within close proximity to many of the candidate CO_2 storage reservoirs, it was necessary to establish a mechanism to determine which point sources are allowed to access a given reservoir's finite storage capacity and in what order this access is granted. Once a reservoir's capacity is filled, any CO_2 point sources still seeking to store their CO_2 must pursue their next best cost-minimizing storage option.

[6] In some runs, more than 50,000 cost pairs are computed.

What follows is a brief hypothetical thought experiment designed to illustrate how the model used here makes these decisions that lay at the heart of the cost curves presented in this report. For this example, imagine an isolated region that contains five large CO_2 point sources (S1 through S5) and three candidate storage reservoirs (R1, R2 and R3). Figure 1.1 is an illustration of this hypothetical isolated region.

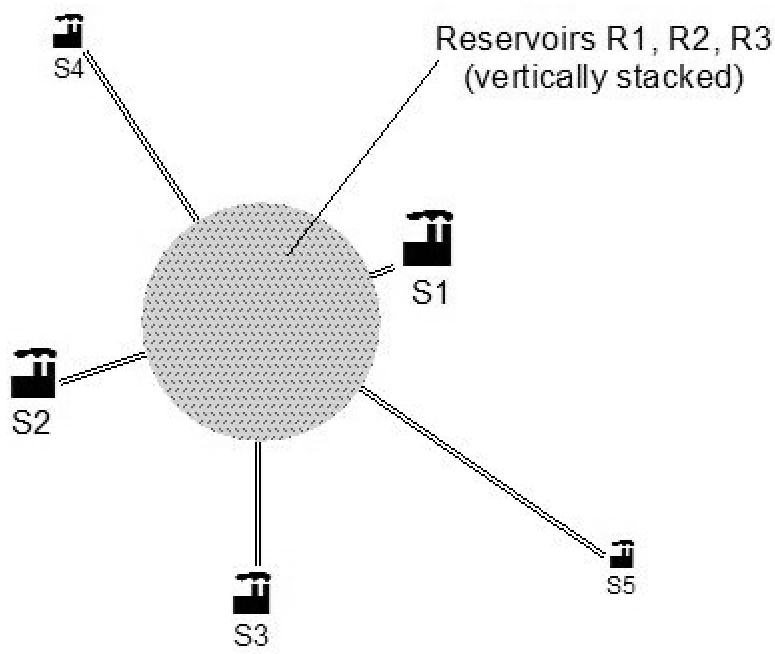

Figure 1.1. Hypothetical Isolated Market for CO_2 Storage

For the CO_2 sources, the following assumptions apply:

- S1 is the largest of the CO_2 point sources (i.e., it has the largest annual CO_2 emissions). S2 is the second largest, etc., with S5 being the smallest.
- S1 is 10 miles (16 km) away from the reservoirs. S2 is 20 miles (32 km) away. S3 is 30 miles (48 km) away, etc.
- All sources produce a uniform pipeline-quality stream of CO_2 at the plant gate.

For the candidate CO_2 storage reservoirs, the following assumptions apply:

- The reservoirs are vertically stacked (i.e., for each individual source, the transport distance to each of the three reservoirs is the same, with each of the three reservoirs occurring at varying depths).

- R1 is the shallowest reservoir and is a small deep unmineable coal seam (i.e., there are revenues from produced coalbed methane which can be used to offset the cost of transport and injection).

- R2 is at an intermediate depth and is a small depleted oil field (i.e., there are revenues from produced oil which can be used to offset the cost of transport and injection).

- R3 is the deepest formation and is a large deep saline formation (i.e., there are *no* revenues which can be used to offset the cost of transport and injection).

The first step is to compute all of the possible pairwise costs for storing CO_2 from these point sources into these reservoirs. This results in 15 possible pairwise costs: S1-R1 (the net cost of transporting and injecting S1's CO_2 into R1 including any offsetting revenue associated with advanced hydrocarbon recovery), S1-R2, S1-R3, and so on until the last cost pair, S5-R3, is reached. Out of this possible set of 15 storage pairs and their associated costs:

- The combination of S1 storing its CO_2 in R1 yields the lowest cost pair (S1-R1). This is because S1 is capable of delivering the cheapest CO_2 to the point of injection as it is located closest to that point (minimizes transport costs) and it has the largest emissions (lowers costs via scales of economy in CO_2 pipeline transport). R1 is also the lowest net cost reservoir because it is the shallowest formation (lower cost for drilling and completing a well) and it is also able to use revenue from produced methane to offset the cost of transport.

- The combination of S5 storing its CO_2 in R3 yields the highest cost pair. This is because S5 is farthest away from the injection point and has the smallest annual emissions, which prevents it from taking advantage of economies of scale associated with transport of CO_2 which are available to larger, higher-volume sources. R3 is the most expensive reservoir because it is the deepest formation and more importantly because there are no offsetting revenues from CO_2-driven hydrocarbon recovery.

- All of the other cost pairs fall between the extremes characterized by S1-R1 and S5-R3.

The last assumption that needs to be introduced is what is referred to in this study as the "10-year rule."[7] This assumption was instituted as a proxy to account for potential difficulties associated with such real world complexities as: siting pipelines, winning regulatory approval for CO_2 injection, and the desire of companies to maximize returns to capital, among others. This 10-year rule says that a reservoir must be able to accommodate at least 10 years' worth of a point source's CO_2 to be considered as a viable storage option. The assumption here is that no company would undertake a CO_2 storage project if they could not count on *at least* 10 years' worth of storage; ten years is the minimum guaranteed storage capacity that would likely be needed, and this number could be much higher.

[7] See section 5.3 for a description of the 10-year rule. Also see section 5.3.2 for a sensitivity analysis which presents results derived from using both a 10-year rule and a 20-year rule.

Returning to this hypothetical example the disposition of the CO_2 is examined:

- Since S1 is capable of providing the cheapest CO_2 at the point of injection, it is allowed to select first which reservoir will accept its CO_2. Since R1 has the lowest cost of storage due to its depth and more importantly the revenue from the produced methane, S1 selects R1 as its repository. S1 is only allowed to store its CO_2 in R1 if R1 can hold at least 10 year's worth of its CO_2. Assume that R1 passes the 10-year rule for S1's CO_2; S1 therefore stores its CO_2 in R1. The model reports the cost S1-R1 for this source. Before moving on to the other sources, the model deducts 10 years' worth of S1's CO_2 emissions from R1's storage capacity as this capacity is effectively walled off and is no longer available to the other point sources.

- The model next moves to S2, which is the next cheapest source of delivered CO_2 at the point of injection. Similar to what happened for S1, S2 will elect to store its CO_2 in R1 assuming that R1 has sufficient *remaining storage capacity*. Assuming here that R1's remaining storage capacity is only capable of storing 5 year's worth of S2's CO_2, S2 will need to seek out its second best storage option, which would be R2. Further assuming that R2 (a depleted oil field) is also not capable of holding 10 year's worth of S2's emissions (as it is a very small depleted oil field), S2 must now seek out its third best storage option, R3. For the purposes of this hypothetical case, R3 has sufficient capacity to hold decades' worth of S2's emissions; and therefore S2 stores its CO_2 in R3. The model reports the cost S2-R3 for this source. In this scenario, R2's storage capacity is essentially "stranded", i.e., it is not economic to exploit its relatively small storage capacity.

- The model then moves on sequentially to S3 and S4. For the sake of simplicity, assume that R3 can hold ten year's worth of both S3 and S4's CO_2 emissions. The model reports the costs S3-R3 and S4-R3 for these two point sources.

- The model now turns to S5 and seeks to store its CO_2 in the remaining formation, R3. However in this hypothetical thought experiment, the remaining capacity in R3 is not enough to accommodate S5's CO_2 emissions for a full 10 years. Thus, S5's CO_2 become "stranded" as there is no suitable reservoir in this hypothetical isolated region that has sufficient storage capacity. No cost is reported for S5.

Even in this simplified, hypothetical thought experiment, a few interesting behaviors are present that mirror behaviors shown in this report's computed CO_2 Storage Supply Curves which are presented in Chapter 5:

1) Costs escalate (i.e., the cost curve is positively sloped) as sources are forced to seek out second- and third-best options driven by the price-based competition for reservoirs' capacity and the fact that this process explicitly accounts for the finite nature of these reservoirs.[8]

2) Several classes of reservoirs are likely to be used at any given time. That is, the large number of CO_2 point sources and the finite storage capacity of each reservoir will likely result in the use of several different reservoir classes at any point in time. The simplistic scenario in which only depleted oil field-based CO_2 storage would be deployed at first followed by at some distant date the deployment of DSF-based CO_2 storage options appears highly unlikely.

[8] In some modeling runs, some sources must seek out their 20th best option for storage capacity.

This is certainly one of the underlying mechanisms that results in the intermingling of reservoirs classes (i.e., Oil, Gas, Coal and DSF) throughout the cost curves presented in this report.

3) Some CO_2 point sources are likely to have their emissions stranded, i.e., the point source will not be able to find a suitable reservoir that meets all of the criteria of the case being modeled. This is demonstrated in the cost curves by noting that not all of the point sources are represented in each case. A small fraction of the point sources are excluded because there are no storage reservoirs within the specified search radius[9] with sufficient remaining capacity to store at least 10 years' of their CO_2.

1.4 Report Structure

The remainder of this report presents the data collected on large CO_2 point sources (Chapter 2) and geologic reservoirs (Chapter 3) in the United States and Canada, the methodology used to model the market-based competition (Chapter 4) for the finite storage capacities of these formations and the results of this modeling (Chapter 5), plus lifetime storage cost curves ignoring competition and the cost of transport (Chapter 6). The report closes with a summary of the major conclusions of this study (Chapter 7) and recommendations for future research (Chapter 8). References (Chapter 9) are included at the end of this report along with appendices which present key attributes of the source and reservoir data collected and applied within this study.

[9] See section 5.2 for an analysis of how differing search radii impact the shape of the cost curves.

2.0 North American CO_2 Point Sources

There are many anthropogenic sources of CO_2 within North America. The focus within this study is on large stationary source CO_2 emitters, such as power plants, cement kilns, sour gas processing facilities, refineries, and other major industrial facilities whose emissions occur at one location and can be captured and separated from the flue or process gas stream in sufficient quantity such that it can be injected and stored in a geologic formation. The current analysis focuses solely on those industrial sources of CO_2 that generate at least 100,000 tonnes (100 kt) of CO_2 per year as CO_2 capture from very small point sources would likely prove to be uneconomic.[10] Therefore, this analysis does not consider CO_2 emissions from small industrial CO_2 point sources, transportation, direct emissions from commercial and residential energy use[11], land use, agriculture, and forestry activities, and similar sources.

2.1 Building the CO_2 Point Source Database

Data for these large CO_2 point sources originated from a worldwide inventory of such sources compiled by the IEA GHG (IEA GHG 2002b). This substantial geospatial dataset catalogues key information on some 14,650 anthropogenic CO_2 point sources around the globe with total CO_2 emissions of approximately 13.5 $GtCO_2$/yr, from a variety of publicly available sources. Where available, reported emissions were documented, and otherwise estimates are listed that are based on plant production and emissions factors. These data, whether reported or estimated, are largely current to the latest year of availability, which for most sectors is 2000 or 2001; the oldest is the cement data, which are estimated from the 1996 production figures published in the latest World Cement Directory (Cembureau 1996). Of all the regions, North America has the highest number of stationary CO_2 point sources. For Canada and the United States, this original dataset contained some 5,240 entries, with a total of 4.6 $GtCO_2$ of annual emissions. Sectors represented within the IEA GHG (2002b) North America data include ammonia, cement, ethylene, ethylene oxide, gas processing, hydrogen, iron and steel, power, and petroleum refining.

This dataset was further updated and refined in several ways. First, geospatial coordinate data were missing for 1,116 or 21% of the sources within the original dataset (84% of these were within the gas processing sector). These were all resolved except for the Canadian gas processing plants, which offered no reliable means of identifying location. Nonetheless, for some sources, the resolution of the spatial coordinate data is not as precise as one might prefer; in some cases county centers were the best locations that could be found. However, for an analysis of this scale, such locations provide acceptable proxy positions. In addition to locations, the gas processing data for Canada were missing other key information, and therefore the Canadian set of natural gas processing facilities contained within IEA GHG 2002b was completely replaced with a new dataset provided by the Alberta Energy and Utilities Board (AEUB) for gas processing facilities located within the Western Canadian Sedimentary Basin. The AEUB also provided new and updated source data (including location, annual CO_2 emissions, and concentration) for a number of other industrial facilities located within Western Canada, including power plants, refineries, cement kilns, ethanol production facilities, and

---

[10] Note that other analyses (e.g., the IEA GHG Early Opportunities study (IEA GHG 2002c)) have applied this same emissions threshold value of 100 $ktCO_2$/year in defining which CO_2 point sources to consider for capture.

[11] An example of “direct emissions” in the residential sector would be the CO_2 emissions from a natural gas fired water heater in a home. Those emissions are not counted here.

oil sands operations (from Fisher et al. 2002). These additions are all current to 2002. For the U.S. data, in addition to tracking down the missing coordinates, the power plant data were completely updated with year 2000 reported data at the plant level (US EPA 2002), ethanol production plants were added (Renewable Fuels Association 2003), and a number of other smaller updates were made.

Other modifications were made to this extensive CO_2 source dataset in order to finalize it prior to initiating the analysis. For example, facilities listed as "retired" were removed, as were planned plants whose start date was listed as being beyond 2005.[12] More than 2,300 sources with annual CO_2 emissions less than 100 kt were also filtered out, representing only a combined 42 million tonnes CO_2 per year, or less than 1% of the total emissions from the region's point sources. The majority of these were very small power plants and gas processing plants (many with unknown emissions). Lastly, 33 plants located in Alaska and Hawaii were removed from the data set in order to focus on the study area of the 48 contiguous U.S. states and Canada.

As discussed above, the entire set of Canadian gas processing plants listed in the original IEA GHG (2002b) dataset was replaced with data from the AEUB, which were deemed to be considerably more credible. Consequently, the original set of 937 records was replaced with a set of 24 large facilities each emitting more than 100 ktCO_2/yr, drastically reducing total CO_2 emissions for the sector. Updated data similar to Canada's could not be located for the U.S., however, a similar reduction in total gas processing emissions might be expected for the U.S. gas processing sector, as compared to the estimates provided in the current IEA GHG dataset which are based on a constant CO_2 content for all U.S. gas fields. The data filtering process described above did result in a modest reduction of U.S. gas processing numbers from 585 plants down to 420, and 1,000 MtCO_2/yr to 820 MtCO_2/yr, however, it is believed that these may still overestimate the total CO_2 emissions from this sector, and that additional detail on typical CO_2 content by gas basin is needed in order to further improve the representation of this sector's CO_2 emissions.

2.2 Characteristics of Large North American CO_2 Point Sources

Figure 2.1 is a map showing the locations of the final 2,082 large anthropogenic CO_2 point sources with annual emissions of at least 100 kt, examined in this report. In total, these plants emit more than 3.8 GtCO_2 per year. As shown, the vast majority of the sources are located in the United States, and concentrated in areas such as the Northeast, Midwest, and South-Central parts of the country. Within Canada, the highest concentration of these large sources occurs in Alberta.

[12] 25 large point sources, with status of "planned" or "under construction" and a start date listed as 2005 or earlier were included; these were considered to have a high probability of being completed and coming on line in the very near term, and are estimated to emit a total of 24 MtCO_2/yr, representing just 0.6% of the final emissions from the large CO_2 point sources evaluated for the region.

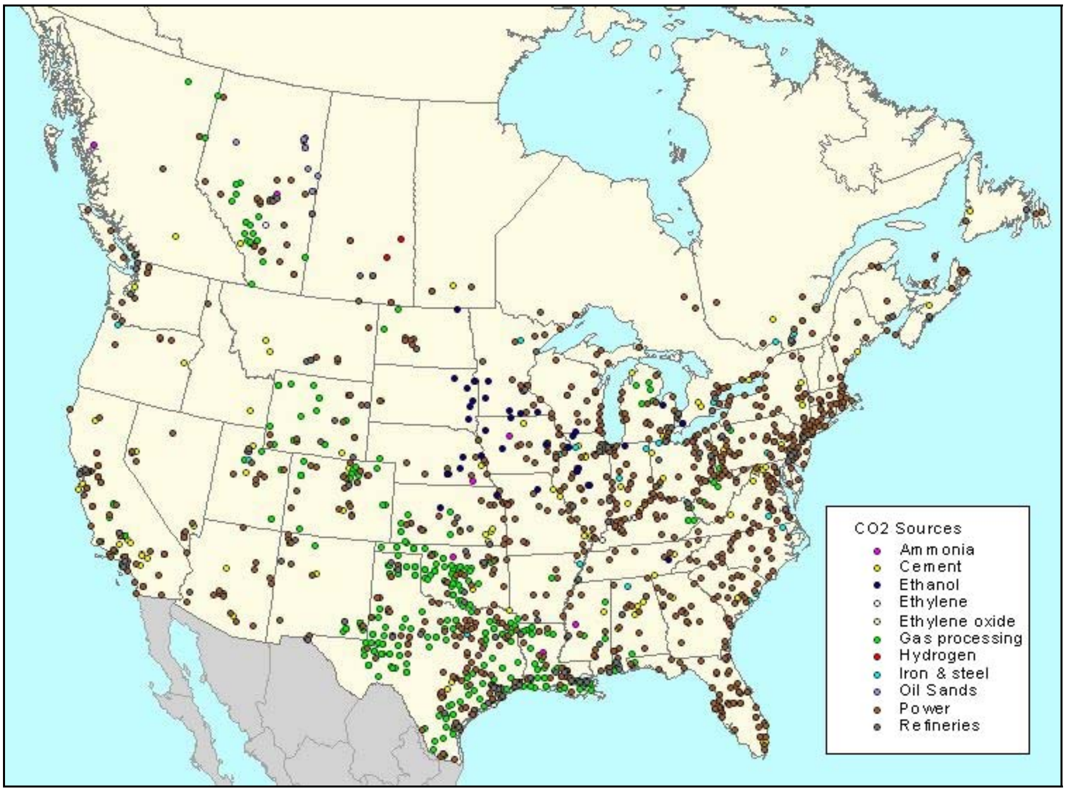

Figure 2.1. Locations of Large CO_2 Sources in North America

Table 2.1 shows the makeup of this set of sources by sector and country. As can be seen here, as well as in Figure 2.2, the electric power industry accounts, by far, for the highest proportion of CO_2 emissions from large stationary sources within North America, in terms of both number of plants and total emissions. Within this sector, approximately 84% of the CO_2 emissions are from coal-fired plants, with 13% attributable to gas-fired power plants, and the remaining CO_2 emissions split between oil-, biomass-, and waste-fired power plants. The three top CO_2-emitting sectors – power, gas processing, and refineries -- contribute fully 92% of the region's total large stationary source CO_2 emissions. Within Canada, however, emissions from oil sands production operations rank second after power plants, followed by refineries and iron and steel production facilities, as can be seen from Table 2.2.

Estimated CO_2 stream purity has been gathered for the majority of CO_2 point sources contained in the dataset. This varies largely by sector, fuel, and technology type, resulting in a wide range of flue or process gas concentrations. For example, high purity sources (i.e., those resulting in CO_2 concentrations greater than 90% by volume) generally include ammonia, ethanol, ethylene oxide, and hydrogen plants, many of which produce nearly pure streams of CO_2 (IEA GHG 2002b). Cement kilns produce approximately 20% pure CO_2, while flue streams from conventional coal-fired power plants and iron and steel mills are typically about 15% CO_2 by volume. Natural gas turbine power generators produce a CO_2 concentration of about 3%, and other source types generally fall somewhere in between 3-15%. As can be seen from Table 2.1, the four sectors with the highest CO_2 concentrations are the four lowest emitting sectors, representing less than 0.7% of the total large point source annual emissions within the region.

Table 2.1. Large (100+ kt/yr) CO_2 Sources and Emissions by Sector

Sector	Total Plants	Canada	U.S.	Total ktonneCO_2/yr	% of Total Emissions
Power	1,156	103	1,053	2,544,117	66.1%
Gas Processing	444	24	420	832,818	21.7%
Refineries	146	20	126	175,130	4.6%
Iron & Steel	53	9	44	95,319	2.5%
Cement	123	18	105	74,360	1.9%
Ethylene	43	5	38	72,340	1.9%
Oil Sands	9	9	0	26,134	0.7%
Hydrogen	40	10	30	9,187	0.2%
Ammonia	25	6	19	8,723	0.2%
Ethanol	35	1	34	6,842	0.2%
Ethylene Oxide	8	1	7	1,259	<0.1%
TOTAL	**2,082**	**206**	**1,876**	**3,846,229**	**100%**

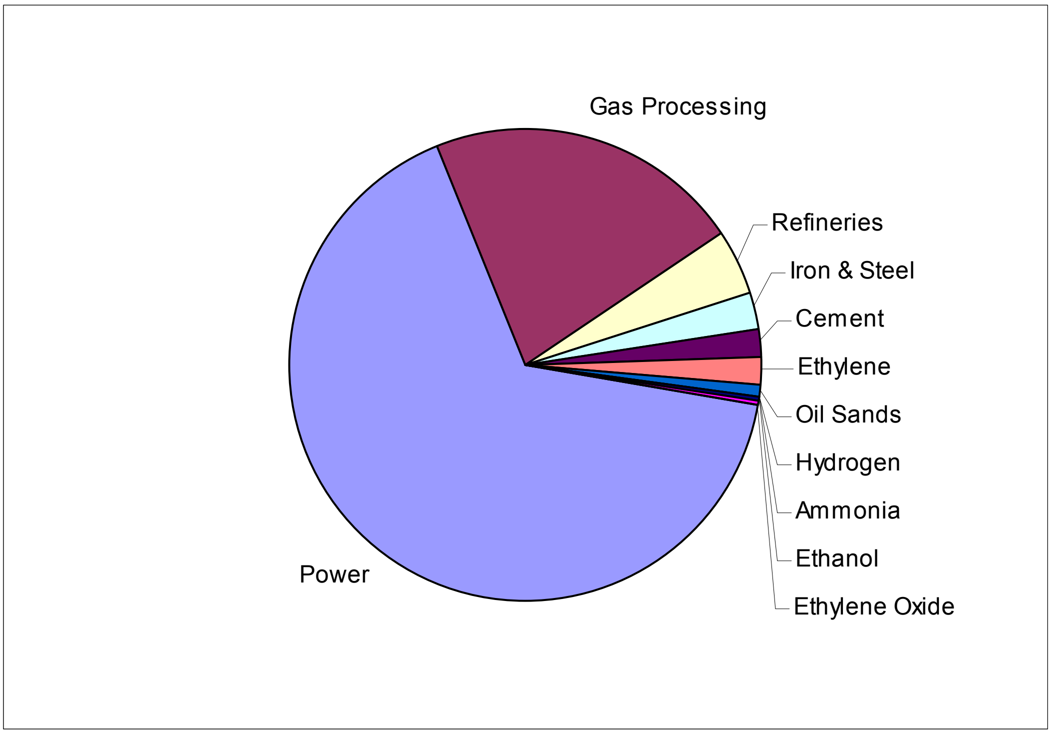

Figure 2.2. CO_2 Emissions by Industrial Sector

Table 2.2. Large CO_2 Point Source Emissions – By Country

Sector	Canada ($ktCO_2$/yr)	% of Canada Total	U.S. ($ktCO_2$/yr)	% of U.S. Total
Power	177,550	63.9%	2,366,568	66.3%
Gas Processing	10,684	3.8%	822,134	23.0%
Refineries	21,596	7.8%	153,534	4.3%
Iron & Steel	14,118	5.1%	81,200	2.3%
Cement	11,929	4.3%	62,431	1.7%
Ethylene	11,473	4.1%	60,867	1.7%
Oil Sands	26,134	9.4%	-	-
Hydrogen	2,349	0.8%	6,839	0.2%
Ammonia	1,765	0.6%	6,958	0.2%
Ethanol	108	<0.1%	6,734	0.2%
Ethylene Oxide	104	<0.1%	1,155	<0.1%
TOTAL	**277,810**	**100%**	**3,568,419**	**100%**

Figure 2.3 helps to illustrate this same point that the majority of stationary CO_2 emissions in North America result from a relatively small number of large, low-purity CO_2 point sources. In fact, as can be seen in Table 2.3, over 75% of the region's CO_2 emissions from large point sources are attributable to the 500 highest CO_2-emitting sources. This means that applying CCS to this subset of plants consisting predominantly of large power plants, gas processing facilities, iron and steel mills, and petroleum refineries, has the potential to mitigate a large portion of the region's large point source CO_2 emissions. The geographic distribution of these 500 largest sources is shown in Figure 2.4, overlain against the set of candidate geologic storage reservoirs in North America (which will be discussed in detail in Chapter 3). As the map illustrates, most of these very large CO_2 point sources are located within close proximity to a potential storage reservoir. 392 of them (representing 61% of the region's total large point source CO_2 emissions) are located right above a candidate geologic storage formation, and 478 (representing 73% of the region's total large point source CO_2 emissions) have at least one potential geologic storage option within just 100 miles (161 km). Again, this indicates that a significant reduction in the region's CO_2 emissions is possible by targeting a modest number of the largest sources, even though (with the exception of most gas processing facilities) they are generally lower-purity sources and would therefore be subject to higher capture costs.

Data for the set of 2,082 large point sources in North America are listed in Appendix A. Key source statistics, such as the number of large sources and total CO_2 emissions are presented for each state and province within the region.

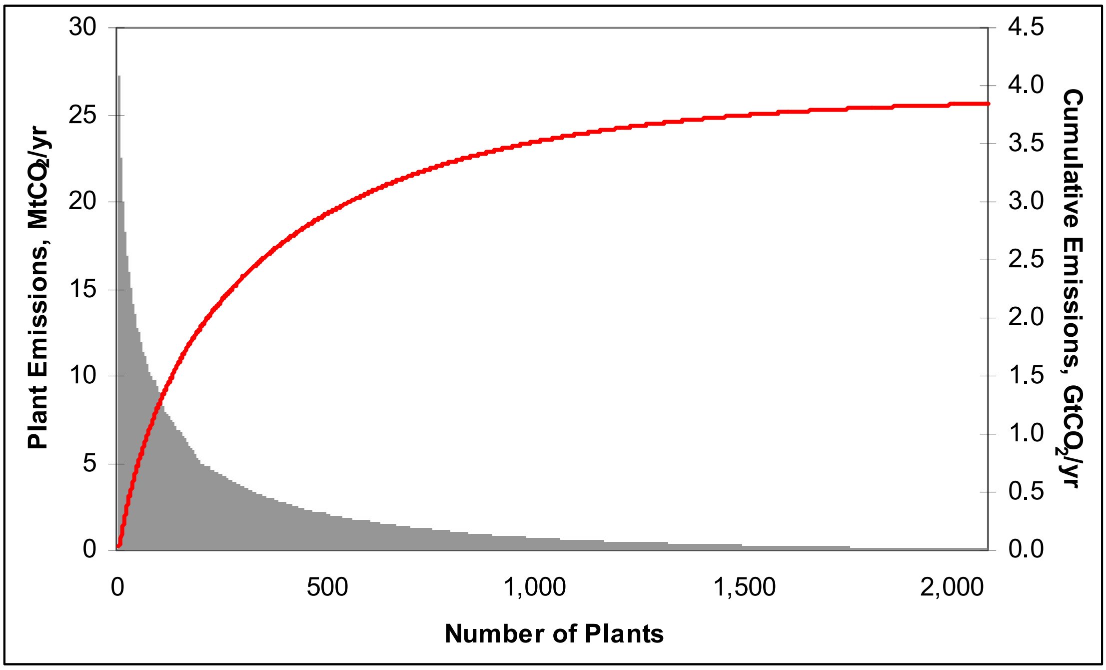

Figure 2.3. Histogram of Large North American CO_2 Sources (bars) and Cumulative Emissions from these Large CO_2 Point Sources (line)

Table 2.3. 500 Largest CO_2 Point Sources

Sector	# Plants	$ktCO_2/yr$	% of Total[a]
Power	326	2,060,697	53.6%
Gas Processing	108	613,904	16.0%
Iron & Steel	23	87,582	2.3%
Refineries	29	80,157	2.1%
Ethylene	11	36,661	1.0%
Oil Sands	3	21,542	0.6%
Total	**500**	**2,900,543**	**75.4%**

[a] Percentage of total CO_2 emissions for all large point sources in North America.

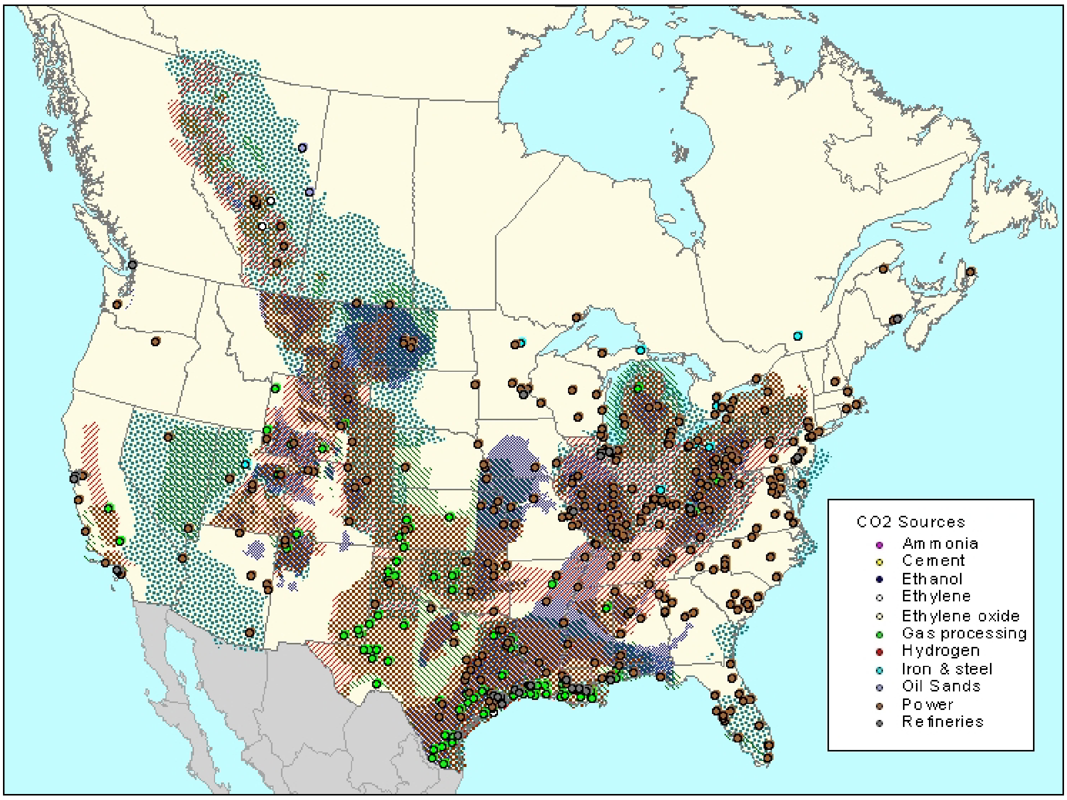

Figure 2.4. Overlay of the 500 Largest CO_2 Point Sources with Candidate Geologic Storage Reservoirs

3.0 Candidate Geologic CO_2 Storage Reservoirs

This analysis evaluates four types of geologic reservoirs that have been identified as candidates for the long-term storage of CO_2 within North America: deep saline formations, depleted gas fields, depleted oil reservoirs, and unmineable coal seams. The focus is exclusively on onshore reservoirs of these types, within which North America has an abundance of potential storage capacity. Nearly 96% of North American CO_2 emissions from the large CO_2 point sources considered in this study occur within 100 miles (161 km) of the identified onshore storage formations, indicating that the vast majority of demand in this region could be ably met by the onshore capacity, rather than by seeking to make use of other candidate CO_2 storage formations such as offshore deep saline formations, or by storing the CO_2 directly in the ocean. Additionally, most offshore oil and gas fields are far less mature than those onshore, reducing the possibility that they would be considered for CO_2 storage or CO_2-enhanced oil recovery (CO_2-EOR) in the near future.

The following sections describe the data and methodologies used to estimate the potential CO_2 storage capacities within these types of geologic reservoirs. For each class of candidate geologic CO_2 storage reservoir considered in this analysis, a description of the reservoir class is presented first, followed by a discussion of the methodologies used to calculate the storage capacities, with a listing of the results, for formations within both the United States and Canada.[13]

3.1 Deep Saline Sedimentary Formations

Deep saline sedimentary formations are present throughout much of North America, and their ubiquity makes this a high-priority class of formations. Figure 3.1 shows the wide areal extent of the candidate North American deep saline formations (DSFs) considered as CO_2 storage reservoirs in this study. Given their significant CO_2 storage potential and their extensive geographic distribution, the discussion of CO_2 storage reservoirs will begin with DSFs.

3.1.1 Formation Description and Attributes

Deep saline formations are deeply buried sedimentary reservoirs filled with saline waters, which offer significant potential for CO_2 storage. Deep saline formations are generally defined to occur at depths greater than 800 meters, the depth at which CO_2 in hydrostatic equilibrium reaches its critical pressure. Such formations contain non-potable, saline water (brackish water and highly saturated brine) that is unsuitable for human, animal, or agricultural consumption, and are typically hydraulically separated from the shallower "sweet water" aquifers and surface water supplies used for these purposes. Formations of this type typically exhibit sandstone and carbonate lithologies, and formation waters often contain between 15,000 and 400,000 mg/L total dissolved solids (TDS).[14] In the United States, for regulatory permitting of certain classes of underground injection wells, aquifers containing water with TDS of less than 10,000 mg/L are defined as underground sources of drinking water. Formation waters are considered saline if they contain in excess of 1000mg/L TDS, and waters with salinity greater than that of seawater (35,000mg/L TDS) are considered brine. Though there are

---

[13] For Canada, the focus on candidate CO_2 storage reservoirs was limited primarily to the western provinces. Reservoirs in eastern Canada were not considered because, being underlain by the Canadian Precambrian Shield, they appear to have negligible storage capacity (Bachu 2003).

[14] Generally, the salinity limit for potable groundwater is established at 4000-5000 mg/L TDS, depending on jurisdiction.

no value-added coproducts associated with CO_2 storage in DSFs, these formations represent by far the largest portion of North American CO_2 storage capacity, accounting for 97% of all capacity in Canada and the U.S. as presented in this report. Typical porosities in DSFs range from 4% to 35%, depending on the maturity and diagenetic characteristics of the particular formation. In fact, porosities may vary significantly (within the same range) within a single formation, since the depositional environment and burial depth greatly impacts porosity, and such porosity varies with depositional facies that vary both vertically and laterally within a cross section, and with the degree of sediment compaction.

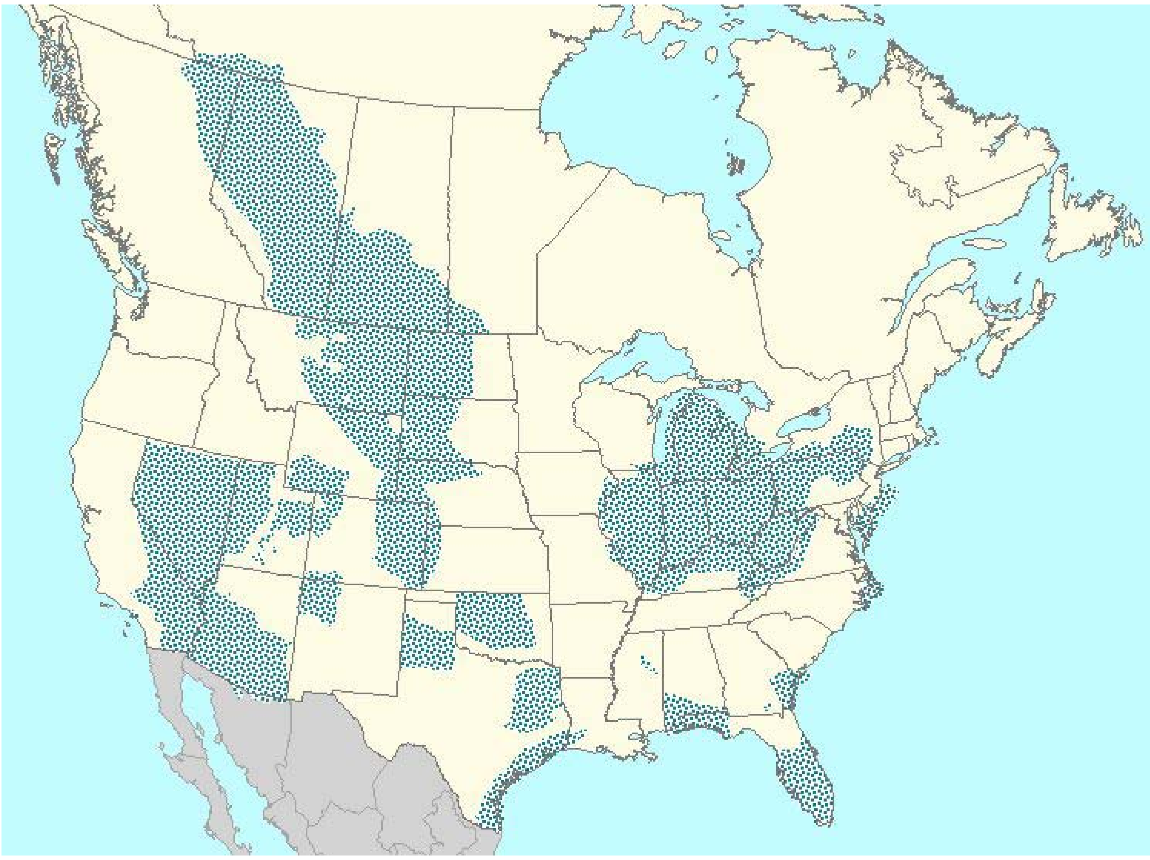

Figure 3.1. Candidate Deep Saline Formations in North America

There are three main trapping mechanisms that act to store CO_2 within deep saline formations. These are: 1) hydrodynamic trapping of a free-phase CO_2 plume; 2) solubility trapping of CO_2 in dissolved phase within the formation water; and 3) mineralization (precipitation) through geochemical reactions with the formation water and host rock. These mechanisms represent the different processes that occur on varying time scales and offer different degrees of permanency to the storage of CO_2. In the case of hydrodynamic trapping, CO_2 preferentially moves into zones of high storage (porosity) and permeability over long residence times, driven largely by natural or injection-induced pressure gradients and by its own buoyancy, and relies on low-permeability traps and barriers to restrict CO_2 migration out of the storage reservoir. This process occurs over tens to hundreds of years, although depending upon the nature of the caprock formations, CO_2 in the storage reservoir can be retained on the order of millions of years. While this process begins upon injection and persists as the other mechanisms develop, mineral trapping via carbonate mineral precipitation within the formation is generally a very slow process, on the order of thousands of years, yet results in effectively immobilizing the CO_2. Dissolved-phase trapping is a strong function of hydraulic gradient, pressure, salinity and temperature, in which CO_2 is held and carried in solution by the slow-moving formation waters. The dissolution process generally occurs at an intermediate time-scale, and may be considered the main mechanism for CO_2 storage calculation in deep saline formations over the short to medium term, as explained by Bachu and Adams (2003). It is for this reason that solubility trapping was the basis for which the CO_2 storage capacities of the North American deep saline formations were evaluated. It should be noted that the selection of solubility trapping for calculating storage capacity does not imply that complete dissolution is a requirement for safe and effective storage since other mechanisms – such as an effective caprock and residual trapping of CO_2 – are likely to be significant and safe trapping mechanisms, especially where the mixing and dissolution rates are slow, at least for the short to intermediate terms.

3.1.2 Calculating CO_2 Storage Capacities – U.S. Deep Saline Formations

Research by Brennan and Burruss (2003) calculated the volume of rock necessary to retain a kilogram of CO_2 present in free phase and dissolution in brine- and freshwater-filled formations. For saline formations, capacity calculations were performed assuming a 4 molar (m) NaCl (approximately 190,000 mg/L TDS) brine and filling the pore space with 5%, 50%, 75% and 100% water saturations, the remaining space being filled with pure CO_2. Because this analysis considers only CO_2 injection into deep saline formations, not in freshwater zones, Brennan's calculated specific sequestration values for a formation saturated with a 4m NaCl solution are applied here.[15] Brennan and Burruss also assumed an average formation porosity of 10%. This is a reasonable estimate for average porosity in these types of formations; however, average porosity in a basin can vary from a few percent to 30% and beyond, with higher porosities providing additional volume for CO_2 storage. Assuming a porosity of 10% for a formation with a true porosity of 5% would result in overestimating the available CO_2 storage volume by 100%; for a zone with 30% porosity, it would result in underestimating potential storage capacity by one-third. This illustrates the need for more reliable formation-specific porosity data. Once more accurate porosity data are uncovered for specific formations, the values calculated here using the Brennan and Burruss assumptions can be recalculated to achieve a higher level of resolution and precision. The Brennan and Burruss results are shown in Table 3.1.

Table 3.1. CO_2 Storage Capacities and Specific Sequestration Volumes at Various Residual Saturations of 4m NaCl Solution (after Brennan and Burruss 2003)

Residual 4m NaCl solution saturation	Storage capacity (kg CO_2 / m^3)	Specific Sequestration Volume (m^3 / tonne CO_2)
5%	57	17
50%	31	32
75%	17	60
100%	2.2	455

As Table 3.1 demonstrates, the difference between the storage capacity of a formation with 5% residual water saturation and a formation saturated at 100% is substantial. The 5%, 50% and 75% residual saturation values appear to allow for greater volumes of potential CO_2 capacity because more of the pore space is occupied with pure phase CO_2. But it should be noted that assuming continued mixing after initial injection of CO_2, formation waters will refill pore space, and residual water

[15] Assuming lower salinities would imply higher available sequestration volumes.

saturation will eventually return to 100% in most of the formation, with varying amounts of CO_2 dissolved in formation waters. A pure, supercritical CO_2 bubble will remain near the injection site for a period of time and, at least in the near term, this is where the bulk of the CO_2 will reside. The ultimate CO_2 storage capacity in solution is dependent not only on water salinity and rock porosity, as shown by Brennan and Burruss, but also on temperature and pressure (Bachu and Adams 2003). It is also highly site-specific based on the local mixing rates, hydraulic gradients, and salinity variations. For example, modeling of an injection scenario for the Mt. Simon Sandstone in the Midwestern U.S. by Gupta et al. (2001), illustrated in Figure 3.2, showed that after 10 years, 14.7% of the CO_2 will have dissolved into formation waters, and at 20 years, 15.9% will be dissolved, leaving 84.1% of CO_2 as pure phase. Furthermore, simulation of injection at other locations within the same formation (Gupta et al. 2004) showed that only about 4.5 to 6% of the injected CO_2 was in dissolved phase for 20 years of injection and 20 years of post-injection period, while for a 500-year scenario with 50 years of injection the dissolution had increased to 8% of the total amount.

Despite the site-specific variations in dissolution rates, it is reasonable to assume that as time elapses, additional CO_2 will continue to dissolve into formation waters until effectively all of the injectate will be present as dissolved-phase CO_2. For example, numerical simulations have shown that a plume of CO_2 will nearly completely dissolve in 3,000 to 5,000 years (Lindeberg and Bergmo 2003, Ennis-King and Paterson 2003). At this point, when there is almost no pure-phase CO_2 remaining in the formation, the formation will have returned to a state of nearly 100% residual water saturation. At this endpoint, the maximum amount of CO_2 that could have been stored in the formation is the value given in the table for 100% residual water saturation. Capacity estimates used in this work assume that the state of 100% water saturation has been reached, and therefore all of the CO_2 is trapped in dissolved phase.

The most comprehensive assessment of U.S. deep saline formations to date has been compiled by Hovorka et al. (2000), in which key geological properties for 21 priority onshore formations[16] (Figure 3.1) were amassed and assembled into a GIS database. This data, combined with the specific storage capacities described above, provide the foundation for the assessment of CO_2 storage capacity in U.S. deep saline formations. Using the digital thickness coverage data, the total volume of each of these 21 deep saline formations was calculated and CO_2 storage capacities were then estimated by applying the specific storage capacity value corresponding to 100% residual water saturation. Because basins were evaluated solely based on the volume of rock present, without taking into consideration other characteristics that may vary from aquifer to aquifer (as these were not consistently available for all formations), resulting storage capacity estimates assume that the entire volume of formation whose top lies below 800 meters is suitable for CO_2 storage. The resulting estimated CO_2 storage capacities for each of these 21 priority DSFs are presented in Table 3.2.[17]

[16] The 21 priority formations represent a sampling of the deep saline formations believed to occur throughout the U.S. and were not intended to comprise an exhaustive accounting of all formations or total storage capacity. Significant additional capacity within these brine formations will likely be uncovered in time, and should be incorporated into this type of analysis as that occurs. In addition, several sedimentary basins present in mid-continent states such as Kansas, Iowa, Colorado, etc. are not incorporated into the database at this time.

[17] To increase spatial resolution of DSF capacity, the formations were also subdivided into specific zones based on depth to top zone, and individual capacities were calculated for each. Results are presented in Appendix B.

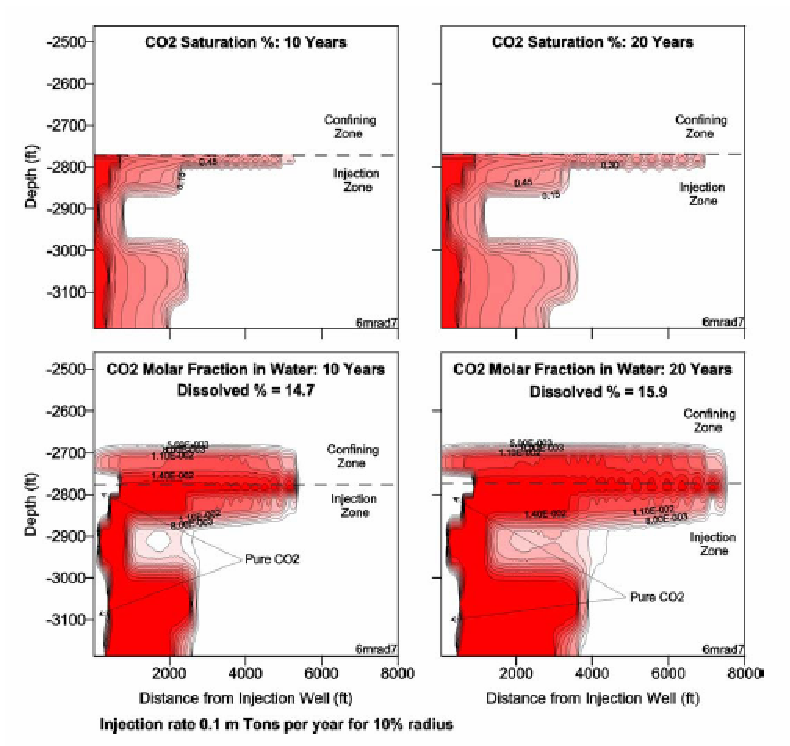

Figure 3.2. Distribution of Pure Phase and Dissolved Phase CO_2 after 10 and 20 Years (from Gupta et al. 2001)

Table 3.2. Calculated CO_2 Storage Capacities for U.S. Deep Saline Formations

Deep Saline Formation	**Capacity ($MtCO_2$)**
Basin & Range	889,055
Madison	379,968
Frio	261,774
Mt. Simon	225,473
Arbuckle	191,050
Jasper	188,971
Lyons	142,520
Granite Wash	118,572
Cedar Keys / Lawson	69,114
Cape Fear	55,684
Lower Potomac	46,135
Glen Canyon	44,503
Morrison	26,705
Fox Hills	21,516
Pottsville	19,202
Woodbine	16,152
Paluxy	12,757
Oriskany	7,606
Tuscaloosa	5,556
St. Peter	4,483
Repetto	2,836
Total U.S. DSF Capacity	**2,729,632**

3.1.3 Calculating CO_2 Storage Capacities – Canadian Deep Saline Formations

Estimates of CO_2 storage capacity in Canadian deep saline formations were made in a similar manner as for the U.S. formations. The calculation of the storage capacity for these Canadian formations focuses on the combined action of solubility trapping and mineral precipitation as components that define the ultimate storage capacity. Due to the timescales of these processes, the non-reactive solubility trapping is considered to be the main mechanism for storage in the short- to medium-term. The work of Bachu and Adams (2003) describes the process to estimate the ultimate CO_2 storage capacity in solution for a DSF as the difference between the total capacity for CO_2 at saturation and the current total inorganic carbon within the formation, dependent on parameters such as pressure, temperature, and salinity.

Applying this methodology to the Viking aquifer in the Alberta Basin in western Canada, Bachu and Adams (2003) calculate an estimated storage capacity for CO_2 in solution of 100 $GtCO_2$. Extrapolating this to the entire Alberta basin while excluding areas believed unsuitable for CO_2 injection and adjusting capacity due to changes in formation characteristics with depth, they estimate that the ultimate theoretical capacity for storing CO_2 in solution at depths greater than 1000 m is on the order of 4,000 $GtCO_2$. This assumes that the formation water in the basin will be saturated with CO_2 everywhere, however, and a more practical, effective storage capacity for this basin is likely on the order of 1,000 $GtCO_2$. Additional formation-specific studies are necessary to further refine this estimate; however, this provides a useful starting point for this analysis. Table 3.3 lists this large single basin representing the deep saline formation data for Canada considered in this study.

Table 3.3. Deep Saline Formations – Canada

Deep Saline Formation	Capacity ($MtCO_2$)
Alberta Basin	1,000,000
Total Canadian DSF Capacity	**1,000,000**

3.2 Depleted Gas Fields

Depleted gas fields have also been identified as prime candidates for CO_2 storage. This section describes how CO_2 storage capacities were computed for the numerous gas basins found in North America. The geographic distribution of the North American natural gas basins considered in this analysis is shown in Figure 3.3.

3.2.1 Formation Description and Attributes

The commercial production of natural gas removes indigenous fluids, including reservoir waters, from the host formation. The resulting empty pore space makes these formations excellent candidates for CO_2 storage. In particular, the presence of a natural gas pool implies good stratigraphic or structural trapping mechanisms in the formation and suggests that the formation should be capable of retaining CO_2 over the long term. Reservoir damage and the effects of depressurization associated with natural gas production on these formations need to be taken into account before utilizing specific depleted gas fields as CO_2 storage reservoirs, but on the whole, these depleted gas formations should possess sufficient porosity, permeability, and barriers to fluid migration to provide stable long-lived CO_2 storage capacity. There are more than 600 sites of natural gas storage in North America, most of them in depleted gas reservoirs, and their experience indicates that formations of this type may be very good candidates for CO_2 storage.

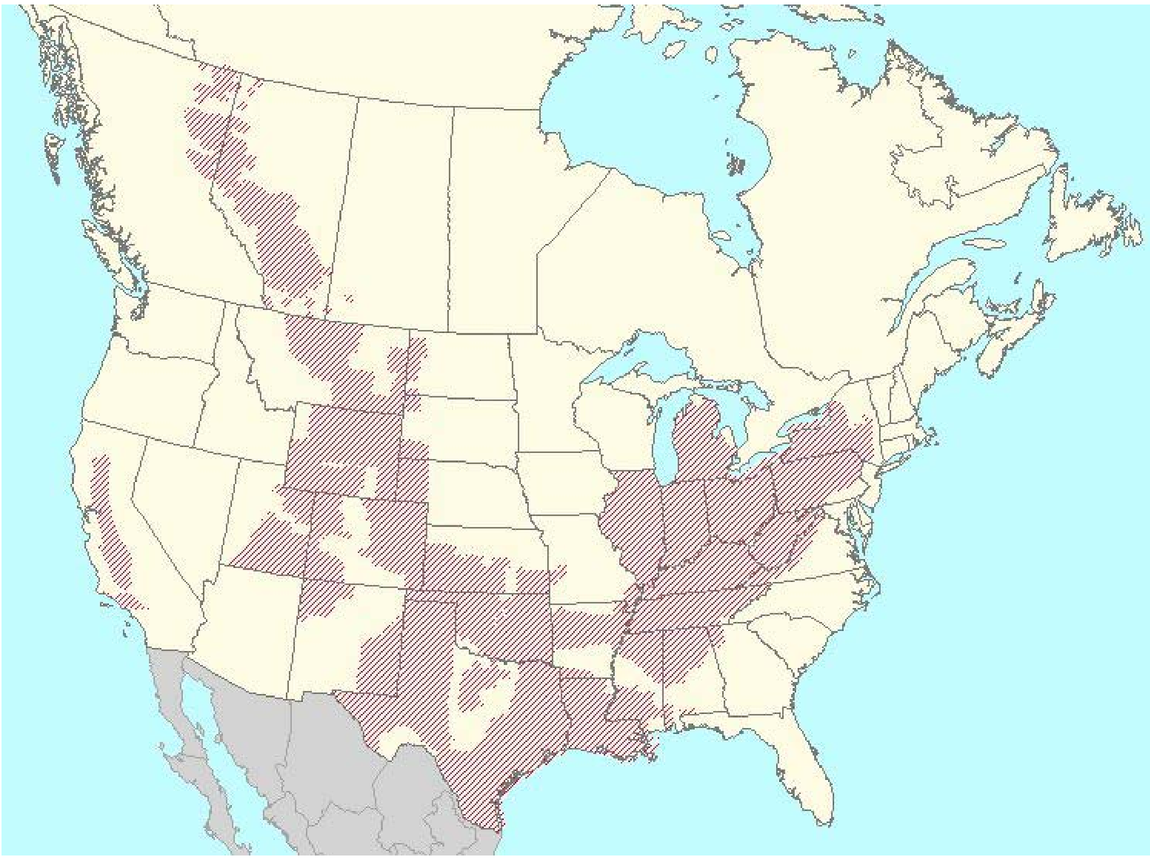

Figure 3.3. Distribution of North American Depleted Gas Fields

Following gas reservoir production and related depressurization, gas-bearing formations are often invaded by waters from adjacent, usually underlying zones. As the system returns to equilibrium over the years following gas production, this water recharge effectively transforms these formations into DSFs, similar in lithology, porosity, permeability and formation fluid composition.

3.2.2 Calculating CO_2 Storage Capacities – U.S. Depleted Gas Fields

The GASIS database includes data on 19,220 gas reservoirs in the 21 top gas-producing U.S. states (GASIS 1999). The dataset was pared down to only those fields for which estimated ultimate recovery (EUR) values were given, or for which the EUR value could be calculated by taking the product of the number of completions for a reservoir and the average ultimately recoverable volume per well. The remaining 5,320 records were then grouped by basin. The GASIS database does not include location information for a vast majority of the reservoirs represented in the dataset, so the data had to be aggregated. The finest level at which this could be accomplished, and for which there were digital map data available, was the basin level and thus data were aggregated by basin. Of the 185 data parameters present in the GASIS dataset, 115 were preserved at the basin level. These include information on lithology, porosity, trap type, gas reserves and other data that may increase the precision of future basin characterization.

Many of the basins in the GASIS database correspond to USGS National Oil and Gas Assessment (NOGA) basins, and may therefore be easily linked to their appropriate digital map data (USGS

1996). For some of the basins, however, there were no corresponding NOGA basin outlines, and therefore these had to be created. Since the GASIS data includes a description of which state and county each reservoir underlies, a digital data theme of U.S. counties was used to select the appropriate counties and convert the resulting groups into approximate basin outlines that were then incorporated into the *CO_2-GIS*. The basins whose outlines were created in this manner include the Mid-Gulf Coast Basin, the Chautauqua Platform, the Central Kansas Uplift, the Ouachita Folded Belt, the Fort Worth Syncline, the Bend Arch, the Central Western Overthrust Basin, the Green River Basin, the Uinta Basin, and the Piceance Basin. It should be noted that, though this approach may seem overly simplistic, when a theme of U.S. county boundaries is displayed over existing USGS NOGA oil and gas plays and basins, it becomes apparent that the two polygon sets share a large number of boundary lines, leading one to assume that a similar county-based method was employed by USGS in developing some of the NOGA basin digital outlines.

Because the coverage of the GASIS dataset is limited to the 21 top gas-producing states in the United States, there are several gas-producing zones that are excluded. These were identified by overlaying the resulting GASIS-developed basins with the USGS ¼-mile cell data for natural gas production covering the entire conterminous United States (USGS 1996). This highlighted some significant areas with gas production that are not covered by GASIS, including basins in California, Michigan, northwest Montana. To address this deficiency and the coverage limitations of the GASIS dataset, NOGA natural gas reserves estimates (USGS 1996) were developed and applied for these regions, along with accompanying digital basin polygons, adding a total of 7 basins. The ¼-mile cell data were also used to validate the basin coverages that were created for the GASIS data, as described above, and revealed that areas in the Gulf Coast region were missing some key production zones, which were subsequently filled in within the basin's polygon.

To calculate CO_2 storage capacity in these gas basins based on total ultimate recovery, a 1:1 replacement ratio was assumed (predicated on the assumption that all of the pore space made available during the gas production phase will be replaced by CO_2). This also assumes that any water that may have infiltrated the formation between extraction and injection will be expelled upon re-pressurization with injected CO_2. Based upon the ideal gas law and the methodology outlined in the IEA GHG (2000) report, volumetric ratios were calculated for each basin, based on the varying compressibility ($z = PV/RT$) of CO_2 and methane under typical conditions often found within gas reservoirs. This volume ratio represents the relative volume of CO_2 (at standard conditions) that may be stored at depth as compared to the volume of produced methane, and can vary from over 3 at a depth of about 1000 m to 1.4 at 4000 m, under typical depth and pressure gradients of 43.3 psi and 1.5°F per 100 feet. For the average depths of the gas basins analyzed here, the resulting volume ratios ranged from 1.43 to 2.69. These were multiplied by the EUR for each basin to calculate the maximum volume of CO_2 that could be stored, and converted to mass at standard temperature and pressure conditions. Finally, to account for water invasion, capillary effects, reservoir heterogeneity, and other factors, a 90% effective capacity adjustment factor was applied as suggested by Bachu and Shaw (2003). The resulting CO_2 storage capacities developed for each basin are shown in Table 3.4.

Table 3.4. CO_2 Storage Capacities of U.S. Gas Basins

Gas Basin	Capacity ($MtCO_2$)	Gas Basin	Capacity ($MtCO_2$)
Anadarko Basin	9,353	Bend Arch	175
Western Gulf	6,900	San Joaquin Basin	146
San Juan Basin	4,500	Uinta Basin	144
Permian Basin	3,482	Chautauqua Platform	115
East Texas Basin	2,324	North-Central Montana	110
Appalachian Basin	1,717	Ventura Basin	105
Green River Basin	1,305	Palo Duro Basin	89
Sacramento Basin	1,053	Cherokee Platform	72
Arkoma Basin	1,013	Williston Basin	62
Fort Worth Syncline	422	Big Horn Basin	61
Mid-Gulf Coast	373	Illinois Basin	33
Michigan Basin	351	Powder River Basin	15
Black Warrior Basin	312	Central Kansas Uplift	15
Sedgwick Basin	267	Paradox Basin	14
Denver Basin	224	Las Animas Arch	10
Southern Oklahoma	221	Central Western Overthrust	8
Wind River Basin	200	Ouachita Folded Belt	7
Piceance Basin	182	Cincinnati Arch	4
Total U.S. Gas Capacity			**35,383**

3.2.3 Calculating CO_2 Storage Capacities – Canadian Depleted Gas Fields

Estimates of storage capacity within Canadian gas reservoirs followed a similar, yet more detailed methodology, due to the availability of more robust and current reserves data. The specific methodology applied to estimate theoretical, effective, and practical storage capacities within gas pools in western Canada at depletion is described by Bachu and Shaw (2004). Theoretical capacity estimates again assume that all pore space freed up by the production of recoverable hydrocarbon reserves will be replaced by CO_2, which is generally valid for reservoirs that are not in contact with an aquifer. This theoretical mass of CO_2 that could be stored within a gas reservoir at depletion is expressed by the following equation, presented by Bachu and Shaw (2003):

$$M_{CO2} = \rho_{CO2r} \cdot R_f \cdot (1 - F_{IG}) \cdot OGIP \cdot [(P_s \cdot Z_r \cdot T_r) / (P_r \cdot Z_s \cdot T_s)] \quad (3.1)$$

where, ρ_{CO2} is CO_2 density, R_f is the recovery factor, F_{IG} is the fraction of injected gas, P, T and Z denote pressure, temperature and the compressibility factor, OGIP is the original gas in place, and the subscripts 'r' and 's' denote reservoir and surface conditions, respectively.

A second assumption, also applied to the U.S. gas basins, is that CO_2 will be injected into depleted reservoirs until the point at which the initial reservoir pressure is re-established, based generally on regulatory policy and concerns for reservoir and caprock integrity. These estimates are therefore conservative because pressure can generally be raised beyond the initial reservoir pressure as long as it remains safely below the threshold value for tensile fracturing, fault reactivation or shear yielding in the caprock. In this case the CO_2 storage capacity would be higher due to CO_2 compression and possibly due to more pore space becoming available.

The *effective storage capacity* depends on intrinsic reservoir characteristics, and takes into account the effects of water invasion, displacement, gravity, heterogeneity and water-saturation. Studies have been performed to examine the effect of underlying aquifers on storage capacity for some 21 reservoirs within the Alberta and Williston basins (Bachu and Shaw 2003, Bachu et al. 2004). In the case of strong aquifers, if the pressure buildup in the reservoir is limited to the initial reservoir pressure, then the reduction in CO_2 storage capacity based on the analyzed cases varies between 0% and 48% for gas reservoirs (averaging 30%). For reservoirs with weak or no aquifer support, a very small reduction (~3%) needs to be considered in light of the fact that water is a wetting phase, hence it should be expected that some irreducible water will be left behind in the pore space by the receding aquifer. Table 3.5 shows the criteria for establishing the strength and effect of underlying aquifers on the CO_2 storage capacity in gas reservoirs in western Canada. The effective storage capacity is then calculated by multiplying the theoretical capacity by this capacity reduction coefficient, as well as an effective storage coefficient, estimated to be 0.9 for gas reservoirs (Bachu and Shaw 2003).

Table 3.5. Criteria for Establishing the Strength of Underlying Aquifers on the CO_2 Storage Capacity in Depleted Gas Fields in Western Canada, and the Corresponding Coefficient of Reduction in CO_2 Storage Capacity

Reservoir Type	WGR (bbl/MMcf)	Aquifer Strength	Capacity Reduction Coefficient
Gas	≥10	Strong	0.70
	<10	Weak	0.97

Using this approach, the theoretical and effective capacity for CO_2 storage in hydrocarbon reservoirs has been estimated using the most recently available reserves databases in each four western Canadian provinces. In all, the reserves databases for Alberta, British Columbia, Manitoba, and Saskatchewan list over 31,000 gas pools. Most reservoirs have a relatively small CO_2 storage capacity (on average 332 kt CO_2 for gas reservoirs), and after screening for a minimum capacity of 1 $MtCO_2$, and a depth range of 900 to 3500 m, 915 gas pools within this region remained, offering a total storage capacity of 4.16 $GtCO_2$.

For each gas pool, coordinate locations were provided, along with depth. Digital outlines of many of the pools were not accessible; therefore the point locations were converted into small polygons to allow consistent application of the source-reservoir pairing and cost model. Also, due to the close proximity and small capacity of many of these gas pools, an aggregation step was performed to group nearby pools of similar depth into larger reservoirs. Each pool was categorized by depth and a 15-mile buffer was applied; all pools within each depth category whose buffers overlapped were then combined into a larger reservoir. Total CO_2 storage capacity was determined by summing the individual pool values, and the resulting depth was calculated as the capacity-weighted average of the individual pool depths. As a result of this process, the total number of gas reservoirs was further reduced to 48 pools and resulted in a more comparable set of gas reservoirs between the U.S. and Canada, for which to apply the cost curve analysis methodology. Table 3.6 lists the total estimated CO_2 storage potential for this set of Canadian gas pools at depletion, summarized by basin. Appendix B lists the more detailed pool and aggregated level results.

Table 3.6. Estimated CO_2 Storage Capacity for Western Canadian Depleted Gas Basin

Gas Basin	Capacity ($MtCO_2$)
Alberta Basin	4,156
Total Canadian Gas Capacity	**4,156**

3.3 Depleted Oil Reservoirs

Similar to depleted gas reservoirs, depleted oil reservoirs offer potential void space created by years of hydrocarbon production. Additionally, the injection of CO_2 into some oil reservoirs may serve to encourage additional incremental production, and extend the useful production life of the field through the process of CO_2 enhanced oil recovery (CO_2-EOR). The distribution of the depleted oil plays in North American considered in this analysis is shown in Figure 3.4.

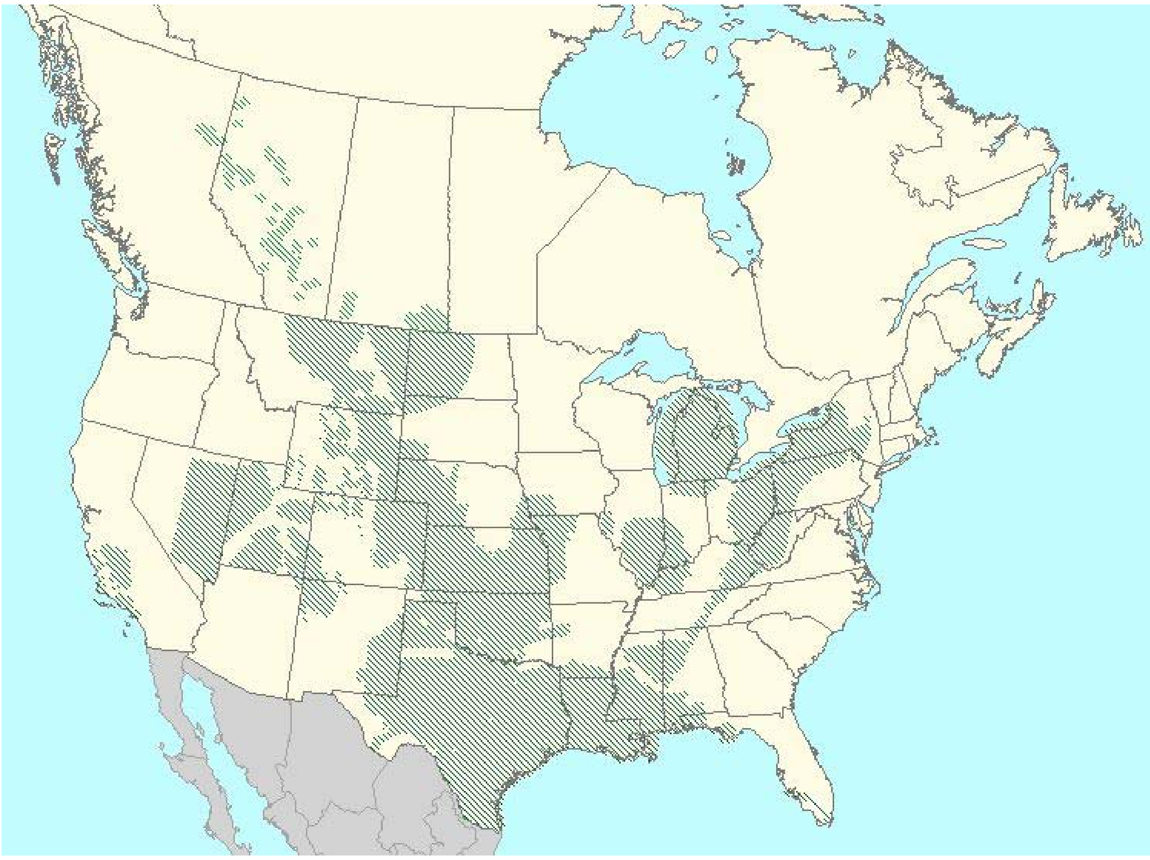

Figure 3.4. Distribution of North American Depleted Oil Reservoirs

3.3.1 Formation Description and Attributes

As the formation fluids that occupy the pore space of oil-bearing reservoirs are produced, void space is created within the rock. This porosity is then available to store injected CO_2. These oil formations have two distinct advantages in terms of CO_2 storage. First, oil accumulates in areas with strong structural or stratigraphic traps that prevent formation fluids from migrating upward through the stratigraphic column. The presence of these traps is a good indication that the reservoir/caprock system that held the oil, water, and associated gas (if any) within the formation for many hundreds or thousands of years may also be capable of retaining injected CO_2 on a similar timescale. Second, as oil is produced out of the host formation, the pressure within the formation drops. Eventually formation pressures reach the point where they are no longer sufficient to drive fluids toward the wellbore. In this case, secondary and tertiary recovery techniques are often employed to repressurize the formation and increase oil production. The use of CO_2-based enhanced oil recovery is now an established practice and is used in mature fields within parts of the United States and Canada to boost production rates. Given the right reservoir characteristics, CO_2-EOR presents an opportunity to offset costs of injecting CO_2 for climate change mitigation via CCS with the revenues associated with the additional incremental recovery produced as a result of CO_2 injection. Here the CO_2 storage capacity in depleted oil reservoirs within North America and the potential for additional oil production via CO_2-EOR are considered.

3.3.2 Calculating CO_2 Storage Capacities – U.S. Depleted Oil Reservoirs

The approach used to calculate CO_2 storage capacities for depleted U.S. oil reservoirs was largely based on the method described in an earlier IEA GHG study (IEA GHG 2000), and applied with minor modifications in the IEA GHG Early Opportunities study (IEA GHG 2002c). The approach was followed as outlined in IEA GHG (2002c) with the major exception that this analysis, rather than using Monte Carlo simulation outputs based on ranges for each associated variable, applied mean or conservative values for variables in each applicable calculation step. Following is a summary of the data and process applied to generate estimates for CO_2 storage and EOR potential for each major oil play within the U.S.

The capacity calculation for U.S. oil plays began with the cumulative production and discovered reserve data, as well as undiscovered oil reserve estimates, for all available U.S. plays contained within the USGS National Oil & Gas Assessment dataset (USGS 1996). Because of proprietary source data issues, discovered accumulation numbers were not available for some plays. For instance, the entire Appalachian Basin province had no discovered accumulation data represented in the NOGA dataset. Therefore, undiscovered reserve data alone were used to estimate EOR and CO_2 storage potential in the Appalachian Basin plays used in this analysis.

Next, as in IEA GHG (2000), the ultimate recoverable reserves (URR) were calculated as the sum of recoverable discovered accumulations and undiscovered reserves.

URR = produced oil + known reserves + undiscovered reserves (3.2)

Continuing with this methodology, calculation of original oil in place (OOIP), the amount of original in-place reserves that could be contacted by CO_2 flood within the reservoir ($OOIP_c$), the proportion of extra recovery to OOIP (%EXTRA), and the total incremental volume of oil produced as a result of CO_2-driven enhanced oil recovery (EOR), was accomplished as follows:

$$OOIP = URR / ((\text{Average API gravity} + 5) / 100) \quad (3.3)$$

$$OOIP_c = OOIP \cdot C \quad (3.4)$$

Where C is the contact factor = 75%.

The proportion of additional recovery to OOIP was then calculated based on API gravity as:

$$\%EXTRA = \%EXTRA_{min} \text{ at API} < 31 \quad (3.5)$$

$$\%EXTRA = (1.3 \cdot API – b) \text{ at API between 31 and 41} \quad (3.6)$$

$$\%EXTRA = \%EXTRA_{max} \text{ at API} > 41 \quad (3.7)$$

In the IEA GHG Early Opportunities study (2002c), probabilistic simulations were used to calculate EOR, and thus ranges were employed for the $\%EXTRA_{min\ and}$ $\%EXTRA_{max}$ of 0.3 to 10.3 and 13.3 to 23.3, respectively. Here, median values for both variables were assumed such that $\%EXTRA_{min} = 5.3$ and $\%EXTRA_{max} = 18.3$. Similarly, rather than varying coefficient b between 30 and 40, the constant median value of 35 was applied here. Once the %EXTRA values were calculated, EOR was derived according to the function:

$$EOR = \%EXTRA \cdot OOIP_c \quad (3.8)$$

Using the relationship between API gravity and depth presented in IEA GHG (2002c) (shown in Table 3.7, and designed to represent the conditions often correlated to EOR recovery factors), the fraction of low- and high-CO_2 oil within each play is estimated, such that the total estimated CO_2 required to produce the estimated available EOR is given by the following:

$$CO_2 = ((\%\text{low-}CO_2 \text{ oil} / 100) \cdot EOR \cdot R_{L\text{-}CO2}) + ((\%\text{high-}CO_2 \text{ oil} / 100) \cdot EOR \cdot R_{H\text{-}CO2}) \quad (3.9)$$

Where $R_{L\text{-}CO2}$ and $R_{H\text{-}CO2}$ represent the typical ratios of net CO_2 injection to oil recovery and are taken to be 0.336 and 0.560 tonnes of CO_2 per barrel of oil, respectively. These ratios are based on observed results from actual CO_2-EOR projects, and these median values presented in the IEA GHG (2002c) were used for this analysis.

Table 3.7. Four EOR Cases with Different Depth/Pressure and API Gravity Conditions (from IEA GHG 2002c)

Depth	API Gravity	% low-CO_2 oil	% high-CO_2 oil
Shallow (< 2000m)	High (> 35)	100	0
Shallow (< 2000m)	Low (≤ 35)	66	33
Deep (≥ 2000m)	High (> 35)	33	66
Deep (≥ 2000m)	Low (≤ 35)	0	100

Because this method relies on empirical relationships derived from ongoing commercial EOR projects, and applies the same relations to all types of depleted oil basins to calculate CO_2 storage capacity, it was important to benchmark the resulting CO_2 capacity estimates against estimates developed by a different approach. Therefore, the resulting net CO_2 storage values for each play were compared to the estimated mass of CO_2 that could be stored at depth, based on typical pressure gradients, to fill the volume of void formation pore space created by the production of 100% of the reservoir's ultimate recoverable reserves plus the oil produced via EOR[18]:

$$\text{Mass } CO_2 = \rho_{CO2,r} \cdot (URR + EOR) \cdot C \tag{3.10}$$

> Where $\rho_{CO2,r}$ = the density of CO_2 at average reservoir depth in kg/m^3; URR+EOR is the total volume of produced oil (MBO), and the conversion C = 1.59E^{-4} Mt-m^3/kg-MBO.

If the mass of CO_2 calculated using this relationship was less than the CO_2 value calculated based on the methodology above, the corresponding EOR values were adjusted downward by the appropriate factor. In such instances, the storage capacity occupied by CO_2 used for EOR would be greater than the total space available in the play without repressurizing the formation past its original (pre-production) formation pressure. While this methodology neglects the presence of post-production water infiltration prior to CO_2 injection, as well as fluid injection and extraction, these adjustments are appropriate to ensure that this methodology, which globally applies empirical observations from existing commercial-scale EOR operations, likely does not overestimate the total volume CO_2 storage potential of these oil plays.

To facilitate source-reservoir pairing and the associated costing methodology, plays with less than one $MtCO_2$ storage capacity were eliminated from the dataset. One $MtCO_2$ was selected as the threshold value for reservoir capacities because a 10-year commitment to sources with minimum annual emissions of 100 kt/yr results in a minimum 1 Mt requirement. This 1 $MtCO_2$ represents the capacity of the smallest reservoir that is able to satisfy the CO_2 storage needs of the smallest point source considered in this analysis, for the shortest minimum filling requirement of 10 years.[19]

Finally, some of the depleted oil plays were aggregated in order to reduce the total number of plays that occur at the same location. In some cases, there were up to 13 plays stacked on top of one another. Many of these plays exhibit similar cost-driving characteristics (depth, API gravity, net CO_2/EOR recovery) such that combining them would not significantly compromise the resolution of the resulting cost curves. Furthermore, because many of these plays are quite small in terms of storage capacity, aggregating them – and thus, their capacity – gives them a better chance for being selected for storage, rather than being bypassed due to capacity constraints. Plays were therefore aggregated if, and only if, the following criteria were met:

- Plays were located within the same basin and share the same areal extent (i.e., they occupy the same surficial domain or significantly overlap one another)

[18] Though this method is less than perfect, it was used here to provide rough validation for the results obtained with the primary methodology that estimates CO_2 storage and EOR potential globally based on a limited set of commercially successful projects within somewhat limited geologic settings.

[19] Refer to Chapter 4 for further details on the cost methodology and analysis assumptions applied within this analysis to compute the Cost Curve for Storage for North America.

- Plays had the same EOR / CO_2 ratio (there are only four possible values for U.S. plays using the above methodology)
- Median depth for each individual play was within 1000 feet of each of the other nearby plays with which it was to be combined.

Based on this method, the total number of U.S. oil plays was reduced from 220 to 112 (excluding Alaska). Using this aggregation method, as many as 13 plays were combined into a single formation, both in the Western Gulf and Louisiana-Mississippi Salt Basin provinces. Table 3.8 lists the resulting CO_2 storage capacity estimates, grouped to USGS province, for the U.S. A detailed listing of the individual and aggregated play capacities may be found in Appendix B.

Table 3.8. Estimated CO_2 Storage Capacity in U.S. Oil Provinces

USGS Province Name	Capacity ($MtCO_2$)	USGS Province Name	Capacity ($MtCO_2$)
Permian Basin	3,085	Denver Basin	71
Louisiana-Mississippi Salt Basins	1,486	Santa Maria Basin	64
Western Gulf	1,342	Central Coastal	61
San Joaquin Basin	1,245	Wyoming Thrust Belt	49
Los Angeles Basin	554	Wind River Basin	37
Cherokee Platform	330	Florida Peninsula	26
Anadarko Basin	318	San Juan Basin	21
Powder River Basin	317	Eastern Great Basin	20
Southern Oklahoma	310	North-Central Montana	17
Nemaha Uplift	231	Las Animas Arch	17
Ventura Basin	224	Cambridge Arch - Central Kansas Uplift	14
Bend Arch - Fort Worth Basin	173	Appalachian Basin	6
Williston Basin	162	Sedgwick Basin	6
Big Horn Basin	144	Arkoma Basin	5
Illinois Basin	127	Palo Duro Basin	4
Uinta - Piceance Basin	116	Marathon Thrust Belt	2
Michigan Basin	98	Park Basins	2
Paradox Basin	76	Black Warrior Basin	1
Southwestern Wyoming	74	Forest City Basin	1
Total U.S. Oil Capacity			**10,832**

3.3.3 Calculating CO_2 Storage Capacities – Canadian Depleted Oil Reservoirs

The data for the Canadian depleted oil reservoirs were developed via a very similar approach as applied to the Canadian depleted gas data described previously in this chapter. And similar to the gas data, recent reserves databases for each of the four western Canadian provinces provided the reservoir characteristics and historical production data to serve as the foundation for estimating CO_2 storage and enhanced oil recovery potential. Again, the methodology used to develop these estimates is described by Bachu et al. (2004) and Bachu and Shaw (2004). Because heavy oil and bitumen reservoirs will have negligible CO_2 storage capacity available following thermal recovery, they were not considered in this assessment.

The same key assumptions are in place as discussed for depleted gas reservoirs: 1) the pore space freed up by the production of recoverable hydrocarbon reserves will be replaced by CO_2, and 2) the injection of CO_2 will proceed only until the formation returns to its original reservoir pressure. The resulting mass balance for oil reservoirs is therefore:

$$M_{CO2} = \rho_{CO2r} \cdot [R_f \cdot A \cdot h \cdot \phi \cdot (1 - S_w) - V_{iw} + V_{pw}] \tag{3.11}$$

where A is area, h is thickness, ϕ is porosity, and S_w is the water saturation in the reservoir, V_{inj} is the volume of injected water, gas or solvent (for flooded reservoirs), and V_{pw} is the volume of produced water. The access to production records for these Canadian reservoirs allows the calculation of volumes of injected and/or produced water, solvent or gas. The CO_2 density at reservoir conditions, ρ_{CO2r}, is calculated from equations of state (Span and Wagner 1996).

The impact of aquifer effect on storage capacity in oil reservoirs was also examined by Bachu and Shaw (2003) and Bachu et al. (2004). The results are shown in Table 3.9. Three additional factors have also been found to control the efficiency of the storage process: CO_2 mobility with respect to oil and water, which leads to viscous fingering; the density contrast between CO_2 and reservoir oil and water, which leads to gravity segregation; and reservoir heterogeneity (Bondor 1992; Doughty et al. 2001). To account for these factors, an effective storage coefficient of 0.5 was determined to be reasonable for oil reservoirs. This coefficient was applied, along with the capacity reduction coefficient related to the aquifer effect, to determine effective storage capacities.

Table 3.9. Criteria for Establishing the Strength of Underlying Aquifers on the CO_2 Storage Capacity in Depleted Oil Reservoirs in Western Canada, and the Corresponding Coefficient of Reduction in CO_2 Storage Capacity

Reservoir Type	WOR (m^3/m^3) or	GOR (m^3/m^3)	Aquifer Strength	Capacity Reduction Coefficient
Oil	≥ 0.25		Strong	0.50
	≥0.15 and <0.25	<1000		
	≥0.15 and <0.25	≥1000	Weak	0.97
	<0.15			

Additional CO_2 storage capacity is available in oil reservoirs that are suitable for CO_2-EOR. Based on review of the literature (Kovscek 2002; Taber et al. 1997; Shaw and Bachu 2002), the following criteria were selected for CO_2-EOR screening purposes: 1) oil density between 788 and 893 kg/m^3 (27°API and 48°API gravity); 2) temperature between 32°C and 121°C (90°F and 250°F); 3) reservoir pressure (P_r) > 7.6 MPa (1,100 psia); and 4) pressure greater than the Minimum Miscibility Pressure (MMP). Although also recommended as screening criteria (Taber et al. 1997) reservoir depth and oil viscosity were not considered due to the fact that oil gravity and reservoir temperature are closely related to these parameters. An analytical method (Bachu et al. 2004, Shaw and Bachu 2002) was used to calculate oil recovery for a series of assumed slug sizes (hydrocarbon pore volume, or HCPV) in a five-spot, water-alternating gas (WAG), miscible flood. This method predicts the fraction of oil produced and the actual fraction of pore volumes of solvent injected at breakthrough, and at any other fraction of HCPV. Assuming that 40% of the injected CO_2 is recovered at the surface (Hadlow 1992) and is re-injected into the reservoir, the CO_2-storage capacity for any HCPV fraction (F_i) of injected CO_2 is calculated according to the following relationships:

at breakthrough (BT): $$M_{CO2} = \rho_{CO2res} \cdot RF_{BT} \cdot OOIP \cdot B_o \tag{3.12}$$

at any HCPV injection: $M_{CO2} = \rho_{CO2res} \cdot [RF_{BT} + 0.6 \cdot (RF_{\%HCPV} - RF_{BT})] \cdot OOIP \cdot B_o$ (3.13)

where RF_{BT} and $RF_{\%HCPV}$ are, respectively, the recovery factors at breakthrough and at the assumed HCPV fraction of injected CO_2; OOIP is the volume of the original oil in place; and B_o is the oil formation volume factor. CO_2 injection at 0.50 HCPV was assumed in this analysis to estimate incremental oil recovery and CO_2 storage due to CO_2-EOR.

This screening and calculation methodology was applied to the more than 10,000 oil pools contained in the most recently available reserves databases for the provinces of Alberta, British Columbia, Manitoba, and Saskatchewan. Just as for the gas reservoirs, a minimum capacity cutoff of 1 $MtCO_2$ was applied, along with a depth range of 900 - 3500m. This reduced the number of oil reservoirs under consideration down to 141. Because many of these 141 pools are located in the immediate vicinity of others, the set of points was then categorized by depth as well as CO_2-EOR oil recovery ratio, and nearby pools (i.e., those that intersect upon applying a 15-mile buffer) sharing these similar properties were grouped into a total of 57 larger reservoirs. For each of these aggregated reservoirs, CO_2 storage capacity and oil recovery potential were summed, and the capacity-weighted depth was calculated. The results of this effort are shown in Appendix B, with the total storage capacity by basin shown in Table 3.10. Note that, as with all of the oil and gas estimates, these capacity estimates are not final and they will likely increase over time as new oil and gas reserves are discovered, or as better recovery technologies are developed.

Table 3.10. CO_2 Storage Capacity in Canada's Oil Provinces

Basin Name	Capacity ($MtCO_2$)
Alberta Basin	508
Williston Basin	436
Total Canadian Oil Capacity	**944**

3.4 Unmineable Coal Seams

Next, the CO_2 storage capacity of unmineable coal seams is evaluated along with recovery potential for CO_2-driven enhanced coalbed methane (ECBM). The distribution of coal seams with potential for CO_2 storage in North America is shown in Figure 3.5.

3.4.1 Formation Description and Attributes

While coal is a significant and abundant energy resource in itself, there is a large amount of coal in the U.S. and Canada that cannot be mined for various reasons, including coals present at depths that make them uneconomical to recover via current standard mining techniques. However, the biologic and geologic processes that turn organic litter into coal also create methane (CH_4). In many coals, this methane is found adsorbed to cleat surfaces. The chemical composition of coal is more stable at a molecular level when CO_2 is adsorbed onto the cleat surface, rather than CH_4. This property leads to the preferential uptake of CO_2 coupled with the release of CH_4. Thus, by injecting CO_2 into a coal seam, methane is chemically released and can be produced and sold. The degree to which a coal will release methane and adsorb CO_2 depends upon the thermal maturity of the coal.

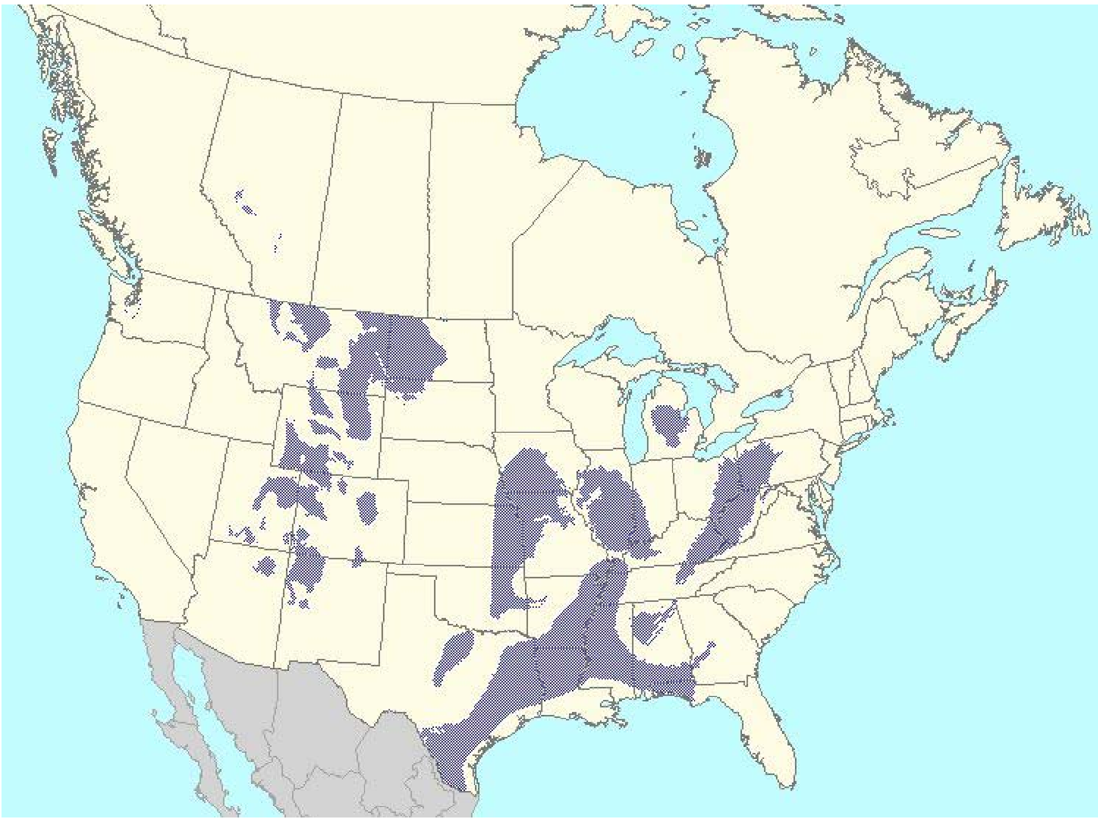

Figure 3.5. Distribution of North American Coal Resource with CO_2 Storage Potential

3.4.2 Calculating CO_2 Storage Capacities – U.S. Coal Seams

The data used to evaluate CO_2 storage capacity in coal basins were taken from Reeves (2003). Reeves' method incorporated several improvements over the previous study on global potential for CO_2 storage within coal beds (IEA GHG 1998), and expanded the coverage to additional U.S. coal basins. The study also incorporated more recent findings regarding relative sorption capacities for CO_2 and CH_4 by varying coal rank, as illustrated in Figure 3.6 (taken from Bustin 2002). Where previous analyses assumed a constant 2 moles of CO_2 per one mole of CH_4 replacement ratio, Reeves applied the ratios presented in Table 3.11, that vary from 1:1 for higher-rank coals to 10:1 for low-rank coals, resulting in a significant impact on the storage capacity of some basins.[20] Reeves' approach allowed for the division of coal basins into "commercial" and "non-commercial" areas of primary coalbed methane production, and applied the rank characteristics of each basin to estimate CO_2 storage capacity and methane recovery potential due to the replacement of primary production volume, and CO_2 injection for CO_2-ECBM recovery within each area. Average and basin-specific adjustments were then applied to limit the storage potential to account for factors such as accessibility, exclusion of mineable zones, or other reservoir constraints. Estimates for several additional basins, excluded from Reeves' study due to their lower potential, were prepared based on similar methodology.

[20] It should be noted that these sorption relationships may not be fully representative of in-situ field response, as tests were conducted on crushed coal samples at sub-critical CO_2 conditions. However, they reflect the best understanding of CO_2:CH_4 replacement ratios at this time, and have therefore been applied in this study.

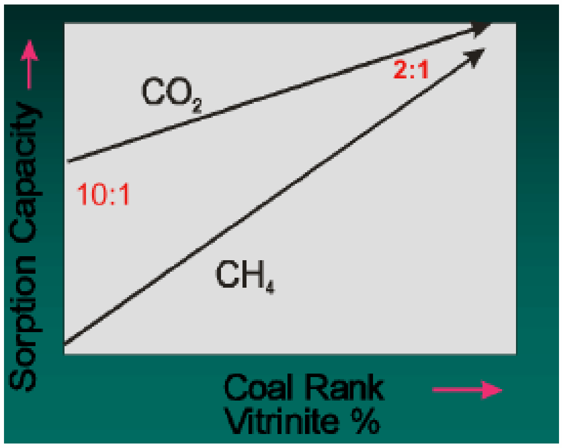

Figure 3.6. CO_2/CH_4 Sorption Capacities vs. Coal Rank (after Reeves 2003)

Table 3.11. Preferential CO_2 Uptake Ratio by Coal Rank (after Reeves 2003)

Coal Rank	CO_2:CH_4 Ratio
Low Volatile (LV)	1:1
Medium Volatile (MV)	1.5:1
High Volatile A (HVA)	3:1
High Volatile (HV)	6:1
Sub-bituminous (SUB)	10:1

To incorporate these data into the *CO_2-GIS*, the data were sorted by basin, and basins were matched to U.S. Coal Basins digital polygon files (Tully 1996). Forest City and Cherokee basins were aggregated in the Reeves data, and thus they were also combined throughout the source-reservoir matching process, although their polygons were also kept separate to allow for the potential that disaggregated data may become available in the future. In using these data, it was assumed that the available capacity from primary recovery given by Reeves is due to initial production by dewatering, and that no dewatering occurs once primary recovery is completed. All non-primary capacity is due to displacement of adsorbed methane by CO_2. Values for CO_2 storage capacity associated with primary, enhanced commercial and enhanced non-commercial recovery are included separately within the *CO_2-GIS*, although the sum of the three values has been used exclusively in total capacity calculations and in reservoir matching and lifetime capacity analyses. These totals are presented in Table 3.12.

Table 3.12. CO_2 Storage Capacity in U.S. Coal Basins

Coal Basin	Capacity ($MtCO_2$)
Powder River Basin	13,600
San Juan River Basin	10,400
Greater Green River Basin	7,800
Uinta and Piceance Basins	4,200
Southwestern Region	3,500
Northern Appalachian Basin	3,400
Hannah-Carbon Basin	3,000
Western Washington Basin	2,300
Gulf Basin	2,000
Henry Mountains Basin	1,600
Wind River Basin	1,400
Illinois Basin	1,300
North Park Basin	910
Cherokee and Forest City Basins	900
Black Warrior Basin	900
Blackfeet-Valier / Great Falls	600
Raton Basin	500
Big Horn Basin	490
Williston Basin	300
Denver Basin	180
Kaiparowits and Black Mesa Basins	120
Central Appalachian Basin	100
Northern Region	60
Total U.S. Coal Capacity	**59,560**

3.4.3 Calculating CO_2 Storage Capacities – Canadian Coal Seams

Major coal beds in Canada are found in the Alberta and Williston basins. Smaller coal basins are found in the Rocky Mountains and on Vancouver Island in British Columbia, in Nova Scotia on the Atlantic coast, and in the high Arctic. However, only coals in the Alberta Basin were considered in this analysis for the following reasons (see also Bachu 2003):

- The Arctic coals are located too far from any CO_2 source and in extremely harsh conditions, making them unlikely candidates for CO_2 storage.
- The coal beds in the intramontane basins in British Columbia are small and far from major CO_2 sources, thus it is unlikely that they will be used for CO_2 storage in the short-to-medium term.
- Coal beds in the Williston Basin in Saskatchewan are shallow and mined for coal used in power generation, and are therefore unlikely to be used for CO_2 storage.
- The coal beds in Nova Scotia are deep, were extensively mined, and indeed could serve as CO_2 storage for nearby sources. However, their capacity is limited and data were not available at the time of the study. In the future the Nova Scotia coal basins may be added to this analysis.

- In contrast, coal beds in the Alberta Basin are extensive, covering a surface of several hundred thousand km^2, ranging in depth from the surface (where they are mined) to 3,000 m depth, and are in close proximity to major CO_2 sources such as power plants, refineries and cement plants.

CO_2 storage capacity and coalbed methane recovery potential for select Canadian coal seams were based on data from the Alberta Geological Survey. Coal beds in three stratigraphic intervals within the Alberta basin were analyzed, including the Ardley, Drumheller, and Mannville zones. For each bed, depth and thickness were taken from geological maps, and pressure and temperature from measurements and geothermal gradients. Coal tonnage was calculated based on area, thickness, and density. Samples of each coal were extracted by the Alberta Geological Survey from wells drilled to each interval during a field program in the winter of 2003-2004. Methane and CO_2 adsorption isotherm analyses were performed in a laboratory on these fresh-drilled core samples to provide relationships for the sorptive properties of the coals under given pressures and temperatures.

Based on these sorption isotherm analyses, methane recovery ratios for these specific coals were determined to range from 5.02 to 1.37 cubic feet per tonne CO_2 (CO_2:CH_4 replacement ratios ranging from 3.78 - 13.89). Utilizing these results along with the maps of the coal zones and tonnage, maps of coal gas content and CO_2 storage capacity per unit area were derived. Areas with high CO_2-storage potential were digitized and the total amount of CO_2 that would theoretically be stored within each bed in that area was calculated, along with expected coalbed methane recovery. Results from this analysis, and the values used to develop the following cost curves for CO_2 storage within North America, are shown in Table 3.13.

Table 3.13. CO_2 Storage Capacity in Canadian Coal Seams

Coal Zone	Capacity ($MtCO_2$)
Ardley	4,421
Drumheller	662
Mannville	306
Total Canadian Coal Capacity	**5,389**

3.5 Summary of North American Candidate CO_2 Storage Reservoirs

Table 3.14 shows the combined CO_2 storage capacity estimates resulting from each of the calculation methodologies described above. Total capacity within all North American onshore reservoirs considered in this analysis is more than 3,800 $GtCO_2$, with nearly 27% occurring within Canada and 73% within the United States. The deep saline formations evaluated here comprise a full 97% of this total storage capacity. Storage in deep unmineable coal seams offers 2.7% of this total capacity, and depleted oil and gas fields have a combined share of 0.9%. However, none of the reservoir storage capacity is insignificant in relation to the CO_2 emissions from large point sources, and their potential role in helping to address these emissions.

Table 3.14. Summary of CO_2 Storage Capacity of North American Geologic Reservoirs

Formation Type	Total Capacity ($MtCO_2$)	Percent of North American Total
Deep Saline Formations – US	2,729,632	71.0%
Deep Saline Formations – Canada	1,000,000	26.0%
Coal Basins – US	59,560	1.5%
Depleted Gas Basins – US	35,383	0.9%
Depleted Oil Reservoirs – US	10,832	0.3%
Coal Basins – Canada	5,389	0.1%
Depleted Gas Basins – Canada	4,156	0.1%
Depleted Oil Reservoirs – Canada	944	<0.1%
Total US Capacity	**2,835,407**	**73.7%**
Total Canadian Capacity	**1,010,489**	**26.3%**
Total North American Capacity	**3,845,896**	

It should be noted that, although the two approaches used for the U.S. and Canada are quite similar in concept, they differ in the level of detail particularly for estimating the CO_2 storage capacity in oil and gas reservoirs as well as coal seams. The higher level of data resolution available for the Canadian oil and gas pools enabled CO_2 storage capacity assessments and subsequent supply modeling to be performed at the reservoir scale, rather than the basin and play level as required by the available U.S. data. Hence, each oil and gas pool within the Alberta and Williston basins was evaluated individually, and those offering a storage capacity of at least 1 $MtCO_2$ were selected for further use. The estimates for the U.S. are based on representative play and basin scale values, and are therefore represented over larger areas, while the estimates for Canada, though covering very large sedimentary basins, are more specific to the reservoir scale, and represented as such in Figures 3.3, 3.4 and 3.5.

While the results of CO_2 storage capacity calculations have been summarized within this chapter at the basin scale, higher resolution data were developed and used in this report's analysis. This more detailed data is reported in Appendix B. Therefore, the number of individual formations examined and modeled is higher than is listed within this chapter. A total of 43 DSFs, 84 depleted gas fields, 161 depleted oil fields, and 34 coal zones were evaluated. Figure 3.7 shows the CO_2 storage capacity distribution of all of these candidate storage formations in North America, by type of formation. In each case, it is clear that a relatively small number of candidate formations provide a significant fraction of the total potential storage resource offered by each type of reservoir. And this is particularly true within the depleted oil and gas fields, where there are numerous fields that have relatively small individual storage capacities. It is important to note that the capacity scale for the deep saline formation chart is in $GtCO_2$, while the others are all presented in $MtCO_2$ – emphasizing once again the relative abundance of storage capacity that the DSFs offer within North America.

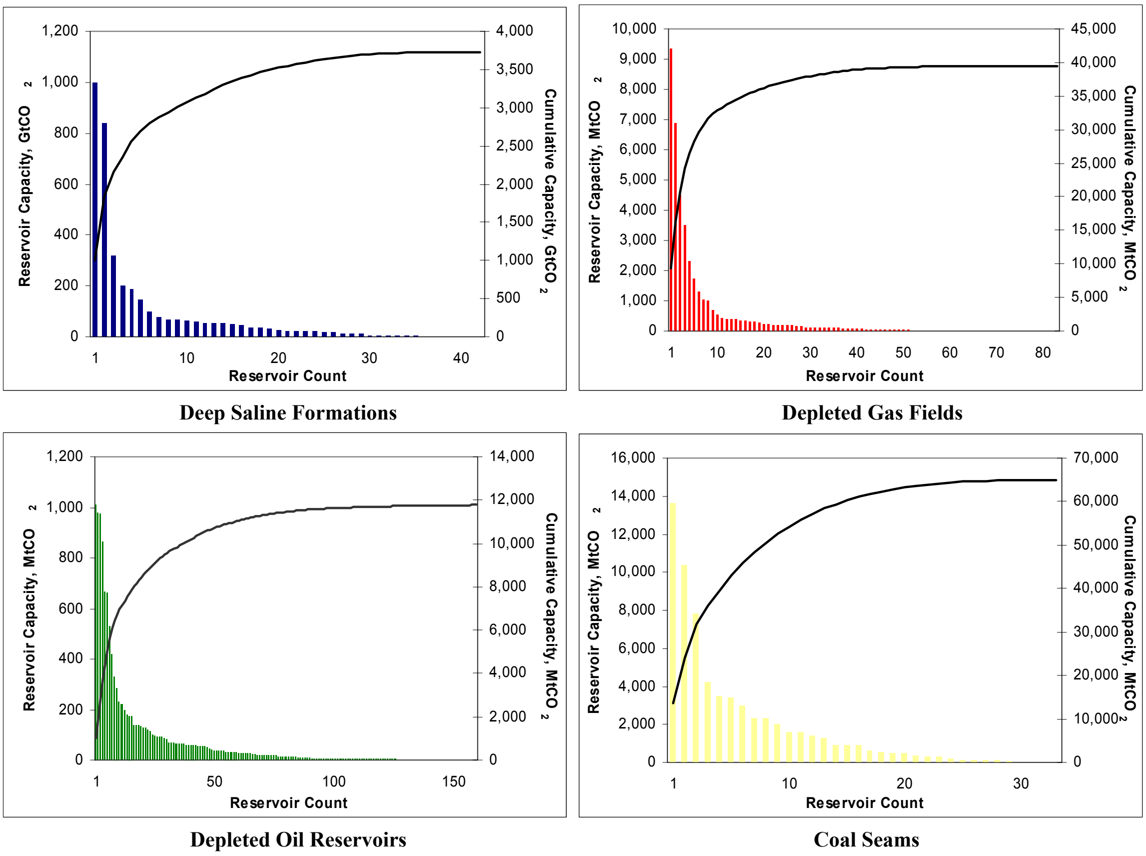

Figure 3.7. Distribution of CO_2 Storage Capacity by Reservoir Type - Top Left = DSF (in $GtCO_2$); Top Right = Depleted Gas ($MtCO_2$); Bottom left = Depleted Oil ($MtCO_2$); Bottom Right = Coal ($MtCO_2$)

4.0 Cost Curve Methodology

This chapter discusses key methodological issues that underlie the CO_2 transport and storage costs presented in this report as well as the reasoning that underlies some of the key assumptions that were employed in this study.

4.1 Approach

The core of this analysis is the matching of the identified point sources with candidate storage reservoirs. Incorporating the updated source and reservoir data into the *Battelle CO_2-GIS* enabled the calculation of a series of pairwise costs[21] for transporting CO_2 from the plant gate of the anthropogenic CO_2 source and the net cost of storing it in each of the candidate reservoirs within a specified distance of the point source. This process generates a suite of potential costs for storing these point sources' CO_2 within the candidate CO_2 storage formations.[22] For the set of sources and reservoirs considered here, nearly 55,000 possible combinations (and, therefore, prices) are generated when the search radius is set to 250 miles (402 km). From this very large population of potential costs, the model employed here selects the minimum cost from each source-reservoir combination, thus generating a storage cost curve for the set of sources considered. Beyond the pairing of sources with potential storage reservoirs, this model was developed to examine the capacities of individual storage reservoirs and their impact on filling scenarios, and the costing of each major CCS component, all integrated within the *CO_2-GIS*. In particular, this allows for the integration of source and reservoir data within a geospatial framework, enabling the examination of not only the technical characteristics of CO_2 production and storage capacity, but also the role that geographical distribution of sources and reservoirs plays in pairing selection, transport requirements, and overall costs.

This cost curve analysis will focus on a number of candidate CO_2 storage reservoirs. CO_2 storage reservoirs considered in the present analysis are:

- depleted oil reservoirs, including existing and prospective areas for CO_2-flood enhanced oil recovery (CO_2-EOR)
- depleted gas reservoirs
- deep saline-filled sedimentary formations, and
- coal seams that might be amenable to CO_2 sequestration and enhanced coalbed methane (ECBM) recovery.

The following sections describe the key assumptions and parameters pertaining to the CO_2 sources, transport systems, and storage facilities, as well as the reservoir access criteria impacting the selection of source/reservoir pairs and the resulting CO_2 storage costs. Levelized capital costs are based on a 25-year design life and ten percent discount rate.

---

[21] See section 1.3 for a description of this pairwise concept as employed in this study.

[22] A description of the economic costing functionality of the Battelle CO_2-GIS, which was used to perform the pairwise transport cost analyses, has been previously published in Dahowski and Dooley (2004).

4.2 CO_2 Source Assumptions Impacting the Cost Curves

Several important assumptions regarding the development and application of the CO_2 point source data have a significant impact on the calculation and presentation of the CO_2 storage cost curves for North America. These are summarized as follows:

- *Capture Cost* – For the purposes of this analysis and per the IEA GHG's preferred methodology for the regional cost curve analyses it is supporting, the cost associated with capturing CO_2 from a dilute flue gas stream or separating CO_2 from a highly concentrated process stream for any point source is not included. Therefore, the cost of capturing CO_2 from any of these diverse classes of point sources is identical at this time and set to \$0/tonne of CO_2.

- *Compression & Dehydration Costs* – The costs of compression and dehydration are also outside of the bounds of the present analysis and will therefore be set to \$0/tonne of CO_2 as well. Each point source will be assumed to deliver a uniform, compressed (to approximately 85 to 156 bars (~1,250 to 2,270 psia) depending on pipeline specifications from Smith et al. 2001a,b), pipeline-ready supercritical CO_2 stream to the plant gate. The net result of these assumptions is that all point sources will be seen as delivering a uniform quality of CO_2 to their respective pipelines. In terms of modeling, this is an important assumption as it indicates that operators of potential CO_2 storage reservoirs will be indifferent as to who supplies the CO_2 for their field; under this set of assumptions, the operator of the storage field will <u>not</u> be willing to pay a premium for CO_2 from a particular class of point sources. This scenario will likely emerge once an interconnected pipeline network is built up and therefore this appears to be a logical assumption for computing the cost of CO_2 transport and storage.

- *Minimum Emissions Cutoff* – The current analysis will ignore any point source that generates less than 100,000 tonnes of CO_2 per year. The assumption here is based upon the idea that – given the capital-intensive nature of carbon dioxide capture and storage, and in particular the need for much of this capital to be spent at the beginning of a project before it is capable of generating CO_2 credits – the owners of very small point sources will be far less likely to employ CO_2 capture and storage systems. For the North American source dataset, this assumption has resulted in the exclusion of over 2,300 very small point sources accounting for approximately 42 million tonnes of CO_2 per year. The vast majority of these are small natural gas processing facilities. Other recent studies supported by the IEA GHG have also applied this minimum threshold of 100 kt CO_2 per year to define the CO_2 point sources that will be considered candidates for employing CCS (see for example, the IEA GHG Early Opportunities study (IEA GHG 2002c) and Wildenborg et al. 2004).

- *Retired or Planned Sources* – The analysis will also ignore point sources believed to be no longer (or not yet) operational; i.e., those units that have been retired since the original data were published, those marked as retired, and those planned sources that are not scheduled to begin operating until after 2005.

- *Capture Efficiency* – A constant capture efficiency of 85% was selected per IEA GHG criteria and applied to all point sources equally. Therefore, the mass flow rate of CO_2 that is transported and injected into a storage reservoir is 85% of the total rated emissions for each plant, and therefore the maximum mass of CO_2 that is available for storage each year within the North American region studied here is 3.27 $GtCO_2$.

- *Projected Emissions Growth* – As part of the original IEA GHG point source dataset (IEA GHG 2002b) projected emissions estimates are included for the years 2010 and 2020. The CO_2 emissions values for 2010 and 2020 were calculated based on the projected growth rate of the industry as well as the technological change in equipment and processes that is expected over each time period. However, because this growth is assigned uniformly to the existing plants of each sector, and does not account for, nor predict new plants being constructed in new locations, these projected emissions data were not used. In order to maintain this study's focus on the determinants of CO_2 capture and storage costs, it is more appropriate to retain the same baseline 2000 emissions and plant locations for all subsequent time periods examined in this report.

- *CO_2 from Natural Underground Domes* – It is assumed at the outset that the current use of CO_2 from *natural domes* for CO_2-driven EOR or ECBM is no longer allowed. That is, only anthropogenic CO_2 will compete for CO_2 storage reservoirs. Even though the use of CO_2 taken from these domes is an integral part of CO_2-driven hydrocarbon recovery as it is practiced in the U.S. today, it seems reasonable to assume that this practice would be discontinued at some point in the future assuming that a price is put on the CO_2 that is emitted to the atmosphere. Anthropogenic CO_2 sources that currently supply CO_2 for EOR (such as the Great Plains Synfuels Plant and the LaBarge natural gas processing facility) will continue to be allowed to sell their CO_2 in this analysis.

4.3 CO_2 Transport

Within the North American region under examination in this study, the development of CO_2 storage reservoir data has been limited to onshore reservoirs at this time. Therefore, land-based pipelines are the method of transport selected for consideration, as they are the preferred method for transporting the volumes of CO_2 that would be required under the assumptions of this analysis. In fact, there are approximately 3,000 miles (5,000 km) of dedicated CO_2 pipelines within this region already, delivering CO_2 to commercial CO_2-EOR projects in areas such as the Permian Basin of West Texas and southeastern New Mexico, the Rocky Mountain Region of Utah, Wyoming, and Colorado, and to the Weyburn Field in Saskatchewan (Moritis 2001 and 2003, Holtz et al. 1999, Hattenbach et al. 1999). See Figure 4.1 which shows existing CO_2 pipeline infrastructure in North America. The longest of these pipelines, the Cortez pipeline, delivers CO_2 over a distance of 500 miles (800 km) from the high pressure and high purity McElmo Dome natural CO_2 deposits in Southwest Colorado to the Denver City Hub in Texas. However, previous research (Dahowski and Dooley 2004) suggests that given the broad geographic distribution of candidate CO_2 storage reservoirs in North America that there will be little need for pipelines of this length under deployment of CCS.

4.3.1 Pipeline Design Approach

While limited regional interconnected CO_2 pipeline networks may emerge over time (such as has occurred in West Texas), most pipeline systems will likely to grow segment-by-segment based upon the lowest-cost CCS opportunities available to each source. Additionally, for onshore geologic storage of CO_2 in North America, the *costs* of CO_2 transport are likely to be best represented as approximating the situation in which each source is connected by a single pipeline to its storage reservoir of choice. It is unlikely that the cost of CO_2 transport and storage would be significantly less if it were instead modeled as an interconnected pipeline network with many point sources feeding into a common trunk pipeline. There are a number of arguments supporting this:

- Our previous research (Dahowski and Dooley 2004), as well as the current examination of sources and reservoirs (see Section 5.2.1) have shown that the vast majority of CO_2 point sources in North America lie well within 100 miles (161 km) of at least one candidate CO_2 storage reservoir. Given that most of the potential cost savings from an interconnected pipeline network would be due to economies of scale in sharing a common trunk line for a significant distance, it is not clear, given the relatively short transport distances likely to be required in North America, that even in the best case there would be significant cost savings potential from such a network.

- As discussed in Section 4.4.1, the range of CO_2 injectivities likely encountered onshore in North America strongly suggest that most large CO_2 point sources such as those considered here are going to require multiple injector wells to handle their CO_2 flow rate. Therefore, a pipeline backbone that collects and transports CO_2 from several large individual CO_2 point sources would deliver a far greater flow of CO_2 to a reservoir, and would therefore require a considerably larger distribution network feeding a more dispersed injection field. This diseconomy of scale at the injection field would likely offset cost savings from the sharing of a common trunk line for some portion of the distance between source and sink.

- As demonstrated by Wildenborg et al. (2004) who undertook an extensive modeling exercise centered on the European Union, there was no significant cost savings in the case in which CO_2 pipeline networks were assumed to exist compared to an alternative scenario in which dedicated source-reservoir pipelines were assumed.

- Finally, as discussed in Wildenborg et al. (2004) the deployment of large shared CO_2 trunk lines would require significant upfront capital expenditures with a relatively long term payback for that investment. It is perhaps unlikely that the rapid development of a large-scale integrated pipeline network is going to arise solely through the agglomeration of many private sector actors undertaking their own profit maximizing decisions as much of the cost savings from such a large interconnected pipeline system would likely accrue to society as a whole through a lower marginal carbon tax. Wildenborg et al. (2004) note that the rapid emergence of an extensive interconnected CO_2 pipeline network would likely require some form of regulatory action or perhaps public sector financing (e.g., loan guarantees) in order to buy down the risk of such a large upfront capital expenditure. It seems unlikely that this kind of large, overt public sector role would take place in North America in the near future.

Therefore, the assumption that every plant will have its own dedicated pipeline, transporting CO_2 to its selected reservoir, serves as a reasonable and conservative basis for the present analysis. The levelized cost of CO_2 transport is calculated by the transport module of the *Battelle CO_2-GIS*, based upon such factors as the distance from point source to selected reservoir, and peak and average CO_2 flow rates. For a more detailed description of the analytical capabilities of the *Battelle CO_2-GIS*, see Dahowski et al. (2001).

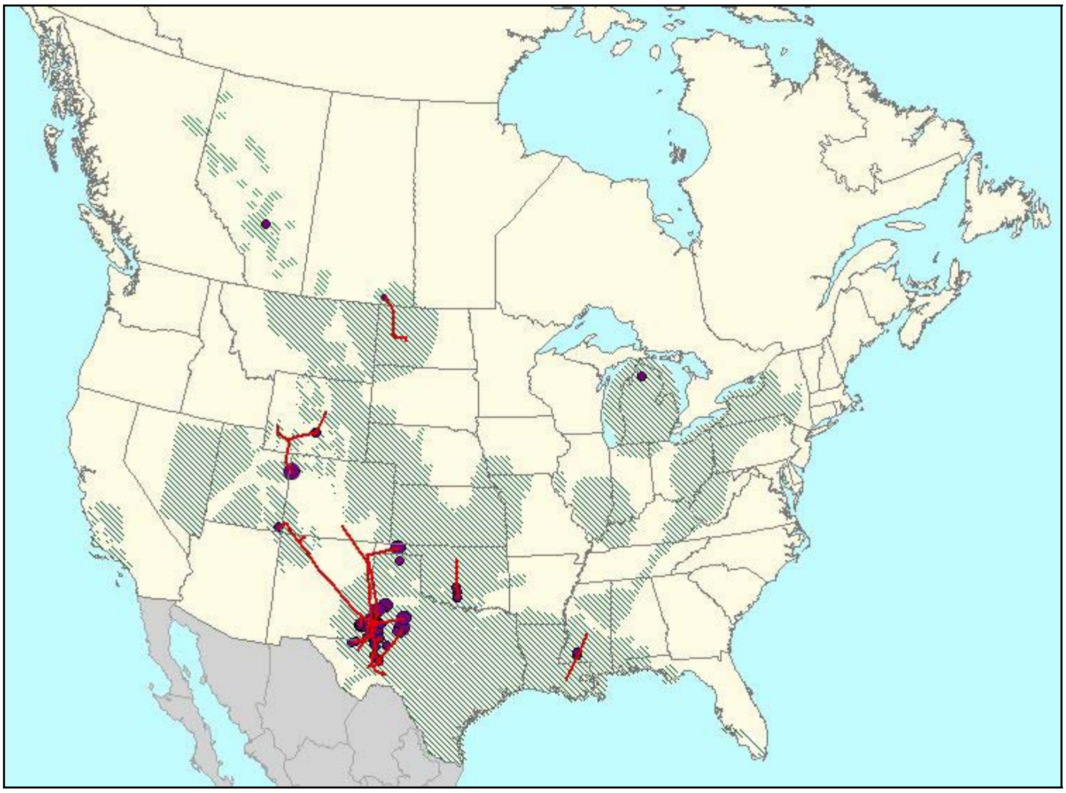

Figure 4.1. Major Existing CO_2 Pipeline Infrastructure in North America (red lines indicate major CO_2 pipelines; purple dots are locations of current commercial CO_2-EOR operations; green hatched areas show the distribution of potential depleted oil plays)

4.3.2 Analysis and Costs

Given the large number of potential cost pairs in North America (up to 50,000), it was not practical to "hand calculate" the cost of transport between each source and all possible reservoirs. Therefore, more project- and site-specific costs, such as additional costs associated with a pipeline river crossing, are not included in this analysis. Instead, a number of simplifying transport cost calculation rules and assumptions were introduced:

- A scaling factor of an additional 17% is applied to the straight-line distance calculated by the *CO_2-GIS* when linking sources and reservoirs to help generate more realistic pipeline distances. This scaling factor was based upon the work of Brown et al. (1993). This scaling factor is a rough factor that is intended to take into account hilly terrain and the need to avoid populated areas, but to be clear, the present analysis does not account for such variations on a site specific basis and all pipelines will apply this average adjustment. Given the large number of cost pairs generated with each modeling run it is simply unfeasible to account for every possible obstacle and terrain nuance between a source and a reservoir, and therefore it is necessary to adopt a global scaling factor such as this.

- A constant 10 miles (16 km) of pipeline is added to the distance calculated by the CO_2-GIS when matching sources and reservoirs to account for locating suitable injection site, field infrastructure, etc. Therefore, even where a CO_2 source is located directly above a candidate storage formation, this minimum length of pipeline is included in the cost to account for CO_2 transport to, and distribution within, a suitable injection field.

- While very long CO_2 pipelines will likely need booster pumps and other measures to keep the CO_2 at a supercritical state, in most areas of North America it is unlikely that such long pipelines will be required, given the previously mentioned observation that the vast majority of sources and storage reservoirs within North America exist in close proximity. Therefore as a simplifying assumption, the cost of booster pumps have been neglected as it is likely that the inclusion or exclusion of accounting for such costs will have relatively little impact on the overall North American Cost Curve.

- The size (i.e., diameter) and, therefore, the cost of the CO_2 pipeline is based upon the total expected flow rate, which will be a function of the size of the point source and resulting CO_2 flow rate, as illustrated below.

- As discussed above, all CO_2 point sources are matched one-to-one to a storage reservoir.

Cost estimates for the CO_2 pipeline model were developed based on 10 years of land construction costs for natural gas pipelines in the U.S. and Canada, as reported to regulatory filing agencies (True 2002). The costs, presented per unit length for pipelines with diameters ranging from 8 to 36 inches (20-91 cm), include materials, labor, miscellaneous (e.g., surveying, engineering, supervision, freight, taxes, administration, overheads, and fees), right-of-way and damage costs. These costs also reflect the variation in locations and conditions encountered across this region, including the impact of specific terrain, land use, and population densities on construction costs. Total per-mile costs were averaged over the 10-year period and plotted along with the range in costs, according to pipe diameter, as shown in Figure 4.2. A regression analysis was performed on these data, providing a pipeline cost estimate of $41,681/in-mile ($10,196/cm-km).

Based upon design rule of thumb for pipeline sizing (0.65 mmscfd/in^2 of pipe area) (Brown et al. 1993), the relation between CO_2 flow rate and pipeline cost per mile were plotted as shown in Figure 4.3. Fitting a power function regression to these costs yields the following pipeline cost equation:

$$\text{pipeline construction cost} = 39{,}409 \cdot (\text{peak } CO_2 \text{ flow rate, tonne per hr})^{0.5} \tag{4.1}$$

Annualizing this capital cost based on the ten percent discount rate over the 25-year study period, results in the following:

$$\text{Annualized pipeline capital cost} = 4{,}335 \cdot (\text{peak } CO_2 \text{ flow rate, tonnes/hr})^{0.5} \tag{4.2}$$

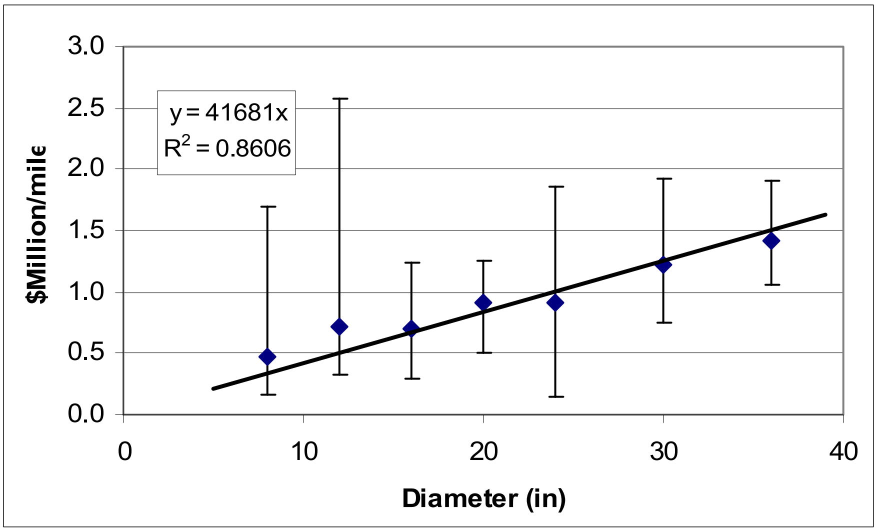

Figure 4.2. Regression Analysis of Natural Gas Pipeline Land Construction Costs (1992-2002) (True 2002)

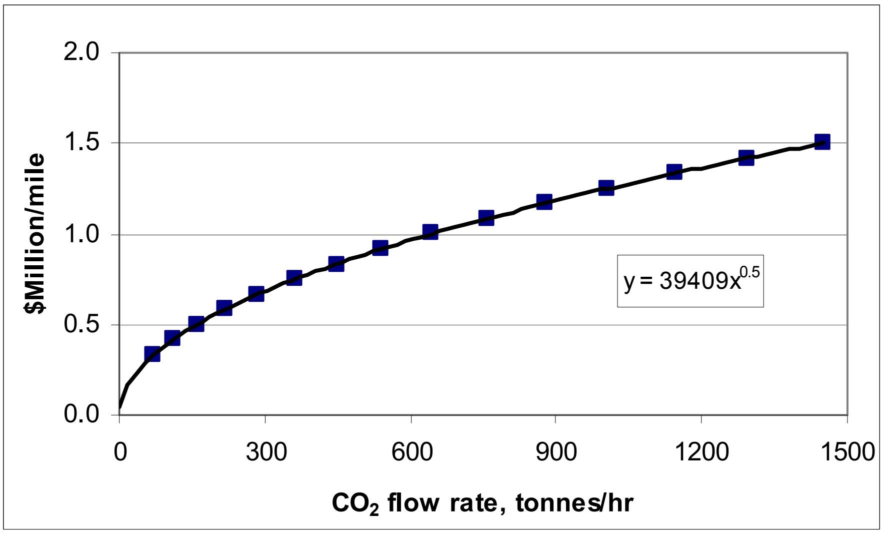

Figure 4.3. CO_2 Pipeline Capital Cost vs. CO_2 Flow Rate

The levelized capital cost is calculated by dividing the annualized cost by the annual CO_2 flow rate. Annual operating and maintenance (O&M) costs were assumed to be 2% of initial pipeline capital cost, so another 2% adder is included in the annualized capital cost, resulting in a total per-mile levelized pipeline cost calculation of:

$$\text{Total Levelized Capital and O\&M (\$/mile/tonne)} = \frac{5{,}123 \cdot (PeakHourlyCaptureRate)^{0.5}}{AnnualCO_2Captured} \qquad (4.3)$$

And total cost per tonne is calculated as:

Total Cost ($/tonne) = (distance + adjustment) · 1.17 · (total levelized capital and O&M) (4.4)

where

- *Distance* = straight-line distance from source to reservoir
- *Adjustment* = 10 miles to account for extra pipeline to locate a suitable injection site within a selected reservoir.
- *1.17* = straight-line adjustment factor to account for likely variation between straight-line distance and real-world routing requirements (based on Brown et al. 1993).

4.3.3 Comparison to IEA GHG Transmission Model

The IEA GHG has developed a detailed transmission model (IEA GHG 2002a), that estimates costs and characteristics for both CO_2 transport and related facilities, but also the transmission of energy including natural gas and electricity. Factors that can be considered within the CO_2 pipeline model include flow rate, transmission distance, pipeline diameter, pressure, terrain, and country. The cost of booster stations for recompression can also be estimated. However, in comparing the resulting pipeline costs output by this model against the 10 years of land construction data specific to the U.S. and Canada as discussed above, the pipeline cost outputs from the IEA GHG model were consistently less for all but very short pipelines. This may be traced to differing assumptions regarding pipeline design requirements, and as a result a choice was made to use the algorithms discussed above based on these North American land cost data, rather than the IEA GHG model.

One feature contained within the IEA GHG CO_2 transmission model is the ability to adjust pipeline costs based on various terrain conditions. This was based on the IEA GHG electric transmission cost model, which assigns specific cost factors to terrain types, such as grasslands, woodlands, and mountainous regions. A terrain model or similar estimation procedure would be required in order to be able to appropriately utilize these cost factors. With an area as extensive as North America, however, this would be challenging, and may still result in only a false sense of precision. Instead, as discussed above, an average distance adjustment factor of 1.17 is applied to all pipelines within the model used here. Coincidentally, this represents approximately the average value of the IEA GHG model's terrain factors, and seems to be an appropriate value to apply for North American pipeline cost calculations.

4.4 Injection Costs

The net cost of CO_2 injection (i.e., including revenue for CO_2-driven advanced hydrocarbon recovery) is also a key determinant of CO_2 transport and storage costs. The following section describes the methodology and key assumptions used to calculate the injection costs used in this study.

4.4.1 Injectivity

In order to account for the differences in flowrates from various sources and the impact such differences have on the total annual cost for injecting CO_2, it was necessary to assign annual CO_2 injectivities for each of the four formation classes included in this report's analysis. Injectivities enable the transformation of annual CO_2 output for each source into the number of wells required to inject that CO_2 into a DSF, a depleted gas field, a coal seam, or a depleted oil reservoir. Injectivities vary from formation to formation, and often vary across a single reservoir. However, because injectivity data are not available for all or even most of the formations examined in this study, it was necessary to generalize the injectivities to the formation-type scale. Therefore, a single representative annual injection rate was assigned to each class of reservoir and applied to the cost curve methodology as described below. As better data become available and field-level analyses are conducted for these formations, these generalized injectivity rates can be replaced by actual injectivities, providing for a more robust model. However, to facilitate the best approximation of this type of field-derived injectivity data in the absence of high-resolution field-specific values, the generalized injectivities used in this study are based upon case studies of operations injecting CO_2 into each type of formation.

Depleted oil reservoirs – Injectivity for depleted oil reservoirs targeting enhanced oil recovery was derived based on a case study of a field within the Scurry Area Canyon Reef Operators Committee unit. The Kelly-Snyder oil field, located in the eastern Permian Basin (West Texas, USA) injects CO_2 via 57 injection wells, and produces oil via 325 production wells. During the early stages of injection, operators recorded injectivities of 5.1 million m^3/d or 180 MMcf/d over 57 wells, for an annual injectivity of 61,000 tonnes/yr-well (IEA GHG 2000, Hawkins et al. 1996, Brock and Bryan 1989).[23]

Unmineable coal seams – Rates of CO_2 injection into coal seams for enhanced coalbed methane recovery vary significantly from one formation to the next. To date, there have been very limited field level pilot projects focused on ECBM. Thus, the methodology employed here for assessing injectivity into ECBM formations draws on field data from just two case studies. Although BP's Tiffany Unit ECBM project in the San Juan Basin (southern Colorado, USA) has been injecting nitrogen through 12 injection wells, and producing methane out of 34 production wells, the injection of an N_2/CO_2 mix has been considered, and injection rates for the field average 736,237 million m^3/d, or 26 MMcf/d per each of the 12 injection wells (Reeves 2001). This converts to 115 tonnes/day-well, or 41,876 tonnes/yr-well. The second ECBM case study, the Burlington Allison Unit ECBM Project in the San Juan Basin (New Mexico, USA) is a much smaller operation, injecting CO_2 through 4 injector wells, and extracting produced methane through 9 production wells (IEA GHG 1998). A total field injection of 85,000 m^3/d, or 3 MMcf/d averaged over each of the four wells, translates into an annual injectivity of 14,500 tonnes/yr-well. ECBM injection rates are a function of many site-specific variables and as such vary locally within a formation, as well as from basin to basin. Because the spatial data associated with these variations were unavailable for the areas analyzed in this study, it was necessary to simply generalize a single injectivity to all coal formations. To do this, the injectivities from the two case studies – BP Tiffany and Burlington Allison – were averaged to arrive at an annual injectivity of approximately 28,000 tonnes/yr-well.

Deep saline formations & depleted gas fields – Injection rates for deep saline formations and depleted gas fields were assumed to be similar, since post-depletion gas formations are invaded by waters from adjacent zones during pressure equalization, creating injection characteristics that are similar those found in DSFs. The case study for this class of formations was taken from the BP Chemical Lima Underground Injection Facility, where BP is injecting liquid waste material into the Mt. Simon Sandstone (northwestern Ohio, USA). The operation uses four injector wells injecting 141 gallons per minute of liquid waste. Based on a supercritical CO_2 density of 0.7 g/mL and the average

[23] 1 metric tonne CO_2 at atmospheric conditions = 534.76 m^3

injection rate into waste storage well #2 as of January 1998, this equates to an annual CO_2 injection rate of approximately 200,000 tonnes/yr-well.[24]

4.4.2 Capital Costs for CO_2 Injection

Although various studies have taken differing approaches to calculating the capital cost associated with drilling, completing and maintaining wells, for consistency and transparency of methodology, a single well cost method was applied to all formation types. Drilling costs are somewhat dependent upon the type of formations that must be drilled through in order to reach the target zone; however it is not practical to apply that level of detail in a study of this scale. Therefore, in order to incorporate the other primary cost driver, depth, a cost-per-depth methodology has been employed to calculate total well capital cost. This analysis applies the well cost evaluation method presented in the IEA GHG "Early Opportunities" (2002c) study, which used 700€/m ($636/m) based upon the economic and engineering report for CO_2 sequestration in saline formations prepared by Smith et al. (2001a and 2001b). Well capital costs were then calculated based on this figure and the depth of each target storage formation.

4.4.3 Operating and Maintenance Costs

Once the construction of durable capital is complete (i.e., injection site selection, drilling, casing, wellhead facility, etc.), costs continue to accrue in the form of costs to operate and maintain (O&M) the injection site. For the purposes of this study, costs associated with the extraction of formation waters are ignored, since there remains some debate as to how much of the produced water would be reinjected versus being remediated at the surface. Therefore, water treatment and storage costs are assumed to be zero.

Depleted oil reservoirs – Annual operating and maintenance costs for depleted oil fields under EOR production were taken from IEA GHG 2000. These costs are listed per barrel of oil recovered; since this study considers the incremental recovery from EOR, tying O&M costs to oil production is a reasonable way to approach such costs for this type of formation. The costs presented by IEA GHG vary by depth of formation and are shown in Table 4.1, and include the cost of CO_2/oil separation, compression, recycling and monitoring at the injection site.

Table 4.1. O&M Costs for EOR Projects by Field Depth (IEA GHG 2000)

Depth range	O&M Cost ($/bbl)
Shallow (800-1500m)	$2.70
Medium (1500-2500m)	$3.38
Deep (>2500m)	$4.05

[24] Another option for determining a representative injectivity is from computer simulations. Based on reservoir simulations for a range of parameters in the Mt. Simon Sandstone, such as those presented in [Gupta et al. 2001 and 2004], injection rates could range from less than 100,000 tonnes/yr to more than a million tonnes/yr in a well. Similar to storage capacity, injectivity is also highly site-specific and likely to range over an order of magnitude even within the same reservoir and 200,000 tonnes/yr-well seems to be reasonable and conservative approximation that can be applied to all of the reservoirs for the current purposes.

Unmineable coal seams – The costs associated with operating and maintaining an ECBM injection field were taken from the Early Opportunities report (IEA GHG 2002c). As with EOR, the total O&M cost is dependent upon the volume of methane recovered, and total cost (including gas treatment and compression) is determined by:

$$\text{Annual O\&M cost} = \$10{,}800 + (\$0.15 / \text{mcf } CH_4) \tag{4.6}$$

Where $10,800 is an annual fixed cost, and the remainder of the cost is variable depending on the total volume of methane produced in that year.

Deep saline formations & depleted gas fields – O&M costs were taken from Smith et al. (2001a). Since there is no recovery of hydrocarbons associated with injection into DSF and depleted gas formations, there are no variable costs that figure into the annual operating and maintenance costs. Thus, a fixed annual per-well cost of $2,301,723 was applied to all DSF and depleted gas fields. This cost does not include the cost of operating compressor stations since apportioned per-well compression costs were not available at the time of this analysis, and the field-level compression costs would be difficult to apply universally to all DSF/gas formations.

Recovery infrastructure costs – Because of the additional capital required to produce oil and coalbed methane from CO_2-driven enhanced recovery operations, it was necessary to account for the additional costs associated with this capital. This was accomplished by calculating the ratio of injection to production wells from the case studies outlined above, and then using those ratios as multipliers by which the injection well capital costs were increased to account for recovery infrastructure costs. The ratios are shown in Table 4.2.

Table 4.2. Injector Well to Production Well Ratios Used in this Study

Formation type	Injection wells : Production wells
DSFs / depleted gas	1:0
EOR / depleted oil	1:5.7
ECBM	1:2.5

4.4.4 Monitoring, Verification, and CO_2 Loss

Monitoring and verification of injected CO_2 is critical to all CCS projects, and as such, these costs should be included in analyses aimed at deriving per-tonne costs for storage operations. Based on the work of Myer et al. (2002) who estimate the costs of monitoring and verification of injected CO_2 to be $0.03/tonne, this cost is accounted for within the error bounds of this study.[25]

[25] Costs associated with lost CO_2, via the migration back to the atmosphere of any injected CO_2 or other leakage from CO_2 storage practices, will not be included in this cost methodology. This issue has been explored in the literature. See Dooley and Wise, 2003.

4.5 Reservoir Filling Constraints

Given the large number of CO_2 point sources near many of these candidate storage reservoirs and given that, via the storage capacity calculations presented in Chapter 3, these formations now have finite storage capacities assigned to them, it was imperative to define a set of rules for determining priority access to these reservoirs. In other words, it was necessary to determine which source gets first access to the reservoir's storage capacity and at what point the entire capacity becomes reserved such that other point sources must seek out a more distant or more costly second-best storage option.

There are two rules assigned here that determine the priority and order of access to a reservoir. First, the source for which the levelized transportation and storage costs are lowest gets first access to a given reservoir, followed by the next lowest-cost source, and so on. In this particular analysis where the cost of capture is set to \$0/tonne CO_2, the determinants of the cost of supplying CO_2 to a field are (1) proximity and (2) the mass flow rate of CO_2 as there are economies of scale in pipeline-based CO_2 transport. Second, as a proxy for the kind of real-world decision-making that one might expect as widespread CCS deployment begins, a rule was established requiring that each reservoir be able to accommodate a point source's CO_2 for at least 10 years (or in later time periods, to have at least 10 years' worth of remaining storage capacity available) before it can be considered as an acceptable storage option for a given source. Without a rule of this kind, lower-cost reservoirs in regions with a high density of CO_2 point sources would be selected as the preferred CO_2 storage reservoir by an implausibly large number of sources, quickly overfilling them. Therefore, this rule acts to ensure that a reservoir's storage capacity is not "oversold" many times over, by directing other point sources to seek out alternative storage options once the given reservoir's capacity has been spoken for. Ten years was selected as a reasonable minimum timeframe to justify CCS infrastructure investment, particularly in light of the many small value-added reservoirs in North America that would get completely bypassed by all sources under a longer (e.g., 20-year) filling requirement.

This "10-year rule" is an important assumption and one that impacts the shape of the curves presented here. This rule also influences the nomenclature that will be used in the remainder of the paper. Hereafter, this ten-year period will be referred to as one "timestep." The cost curve figures that follow are all labeled "annual," meaning that this is the amount of CO_2 that could be injected in one year if all point sources sought out their lowest-cost available CO_2 storage option. That is, these are annual figures (total CO_2 stored in one year) but the "10-year rule" impacts this by enforcing that the annual storage cost curve for each of the ten years within a given timestep is identical to the others. Lastly, as noted above, this analysis explicitly accounts for costs associated with the additional infrastructure needed for EOR and ECBM recovery (i.e., recovery wells in addition to CO_2 injector wells) since they will likely factor into a source's evaluation of CO_2 mitigation options once CCS begins to deploy on a large scale basis.

5.0 North American Cost Curves for CO_2 Storage

This chapter presents the results of the economic modeling performed for this study that spans all of the data and methodologies presented in Chapters 2, 3, and 4. The heart of this analysis is the model's computation of the set of lowest cost values for all of the CO_2 point sources and candidate CO_2 storage reservoirs subject to a set of initial boundary conditions (e.g., maximum search radius, the price of oil). Before reading this chapter, readers are encouraged to read the explanation of the "pairwise" terminology contained in the short thought experiment that comprises Section 1.3. Before proceeding, several key points should be stressed for readers to be aware of when reviewing these results:

- The cost curves presented here do not account for the cost of CO_2 capture, dehydration, and compression. This was done intentionally to maintain a clearer focus on the determinants of the net cost of CO_2 transport and storage.
- These CO_2 storage supply curves assume that all possible large CO_2 point sources employ CCS technologies and that each of them seek out their lowest-cost storage option on January 1 of Year Zero. While this assumption is certainly an oversimplification, the resulting cost curves provide insight into how the North American market for CO_2 storage capacity would evolve once CCS technologies begin to be substantially deployed.[26]
- The x-axis of each cost curve is labeled "Cumulative Supplied CO_2 Capacity (Annual)." This is the annual volume of CO_2 capacity supplied to large point sources seeking to dispose of their CO_2 within the modeled time period. Therefore, due to the ten-year filling cycle employed in this analysis, the curve for the entire ten-year interval represented by the annual curve would look identical, except for a ten-fold increase on the x-axis.

5.1 Defining the Reference Case

For this analysis, it was necessary to choose baseline assumptions for the evaluation of a Reference Case scenario. The primary assumptions were then varied in a series of sensitivity analyses. The primary assumptions, and those for which sensitivities were determined, are the search radius, the available capacity time horizon, energy prices, and production infrastructure requirements.

As described in Chapter 4, each model run results in tens of thousands of matched source-reservoir pair costs. This number would increase exponentially if all sources were paired to all potential storage reservoirs. For this reason, it is necessary to set a maximum search radius to constrain the number of possible cost pairs that need to be examined. The Reference Case assumes a 100-mile (161-km) search radius. In other words, each CO_2 point source is allowed to search for all suitable candidate CO_2 storage options within 100 miles of its location. The validity of this assumption is assessed in the sensitivity analysis section of this report.

---

[26] These cost curves should not be interpreted to imply some strict temporal progression moving from left to right across the curve and they are not predictions for how this technology will unfold over the course of the coming century. Instead, they provide valuable insight into how CCS technologies might deploy in light of assumptions about the policy, economic and industrial environment of any number of possible futures.

Because some of the storage reservoir types (i.e., depleted oil reservoirs and coal seams) provide incremental recovery of value-added hydrocarbons associated with CO_2 injection, and because the revenues associated with these coproducts may be used to offset the costs of transport and injection of CO_2, the prices of oil and natural gas must also be factored into the analysis. The Reference Case assumes an oil price of \$23/bbl[27] and a gas price of \$3.14/mcf.[28]

The incremental recovery of oil and gas from these value-added formations also requires additional infrastructure. For instance, while this analysis assumes that injection into deep saline formations requires only injection wells, CO_2 storage combined with enhanced oil recovery or enhanced coalbed methane recovery will also require production wells to recover the oil or gas. Since the revenues derived from these incremental volumes of recovered hydrocarbons can be used to offset the costs of transport and injection, the positive costs of this additional production infrastructure are included in the Reference Case. The Reference Case assumes that additional wells must be drilled and completed for each injection well according to the ratios set forth in the injectivity case studies presented earlier. For EOR operations, this corresponds to 5.7 production wells per injection well; in ECBM operations, 2.5 production wells are required per injector.

In order to account for the fact that CO_2 pipeline and injection infrastructure represents a sizeable capital investment, and that point sources will not elect to utilize formations in which they can only store a few years of their CO_2, it was necessary to assume a minimum timeframe over which a CO_2 point source could utilize a reservoir without having to relocate to another formation. The Reference Case assumes a minimum capacity time horizon of ten years (the “10-year rule”). Therefore, in order for a source to be paired with a potential storage formation, that formation must be able to commit sufficient capacity to that source to store at least 10 years of its captured CO_2.

5.2 Reference Case Results

In the Reference Case, 93% of the large North American CO_2 point sources, representing almost 96% of the CO_2 that’s potentially available for capture[29], have at least one potential storage reservoir within the 100-mile (161-km) search radius. 3,121 $MtCO_2$ of annually captured CO_2 gains access to a storage reservoir, while 11 $MtCO_2$ from 20 plants is not able to access any of its storage options, due to preferential filling by other, lower-cost sources (likely larger sources, located closer to the reservoir). This 11 $MtCO_2$ is thereby left “stranded”, unable to access the available storage capacity within the specified search radius. Table 5.1 shows how CO_2 from these point sources is allocated among the various candidate CO_2 storage reservoirs.

As can be seen from Table 5.1, the total cost for CO_2 transport and storage ranges from -\$7.13 to \$54.70/tonne CO_2. Storage in value-added formations (coal and oil) account for 45% of all supplied capacity, with the remainder coming in the form of DSF and depleted gas reservoirs. Most of the capacity in DSFs and gas formations is available at around \$12/tonne CO_2, and this is what makes up the long, relatively flat middle part of the CO_2 storage supply curve for the Reference Case shown in Figure 5.1. Beyond about 3,000 $MtCO_2$ supplied, the curve turns sharply upward. This part of the CO_2 storage supply curve is comprised of the CO_2 point sources that lie the farthest from their

[27] Based on IEO 2003 projections to 2005; assumed to be wellhead prices rather than spot market prices.

[28] Based on stipulated IEA GHG price of \$3/GJ gas price less 10.8% adjustment back to wellhead price based on EIA Henry Hub-to-wellhead conversion.

[29] Based on an 85% capture efficiency, as noted in section 4.2.

selected reservoir, and therefore their cost of storage is dominated by transportation. But below the threshold price of $12/tonne CO_2 for the high-capacity DSF and gas formations in North America, there is 1,343 $MtCO_2$ of storage capacity available in value-added formations. Of this, 667 $MtCO_2$ are available at negative transport and storage costs (i.e., net cost < $0/tonne CO_2).

Table 5.1. CO_2 Transport and Storage Supply Summary for the Reference Case

Reference Case	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	841	394	467	222	1,924	20
Total Supplied CO_2 Capacity (Mt/yr)	1,074	1,124	638	285	3,121	11
Total CO_2 (% of total available CO_2)	33%	34%	20%	9%	95%	0.3%
Minimum price ($/tonne CO_2)	$12.49	-$7.13	$12.16	-$6.61	-$7.13	
Maximum price ($/tonne CO_2)	$37.27	$26.84	$31.39	$54.70	$54.70	
Total pipeline in use (miles)	34,453	18,781	17,277	8,636	79,147	
EOR Recovery (MMBO/yr)					726	
ECBM Recovery (Bcf/yr)					3,076	

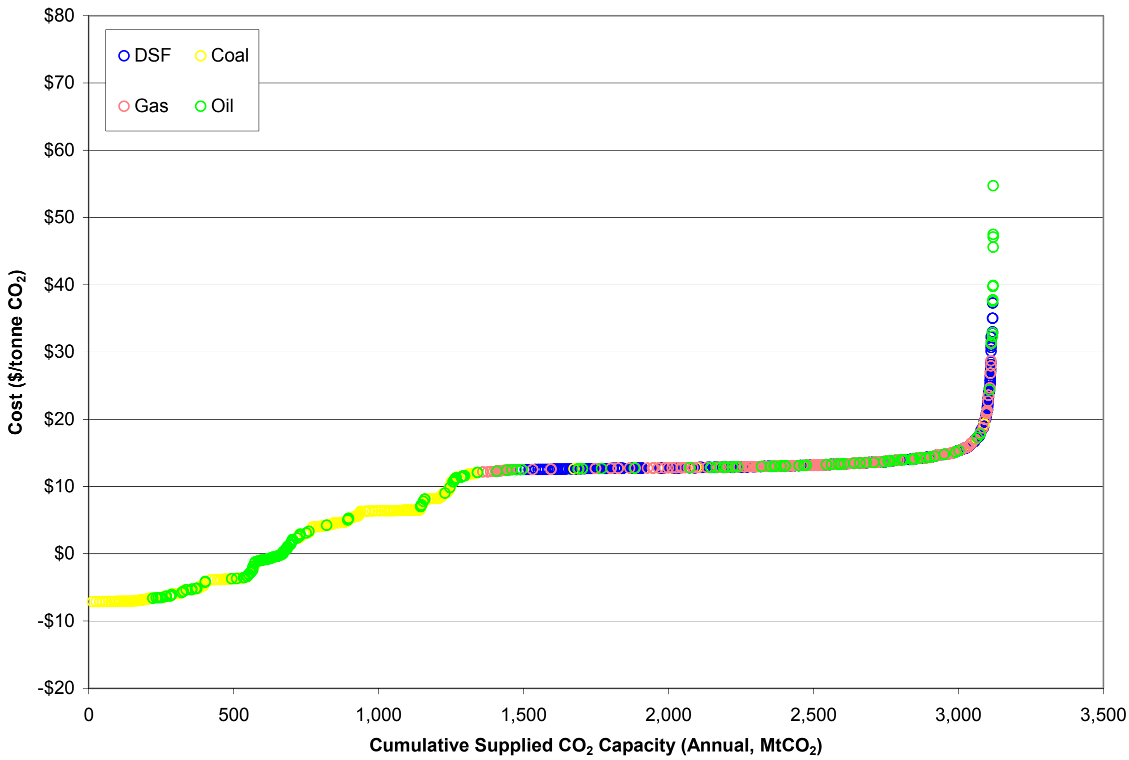

Figure 5.1. CO_2 Storage Supply Curve for North America for the Reference Case

In addition to the cost data, the general shape of the cost curve and the intermingling of the various storage reservoirs provide rich insights on how CCS systems might deploy in North America. First, as alluded to above, the Reference Case CO_2 Storage Supply Curve has essentially four major regions: (1) a negative cost storage region comprised of coalbed and EOR-based storage opportunities, (2) a region of low but positive cost storage options once again comprised of EOR and coalbed-based storage opportunities, (3) a large flat section containing all of the storage reservoirs but dominated by deep saline formations and depleted gas fields, and (4) a nearly vertical region on the far right side of the curve representing mostly small CO_2 point sources that are just within the 100 mile (161 km) search radius and are able to access only deep saline and depleted gas field storage space, or more costly depleted oil reservoirs.

Table 5.1 also highlights the total length of pipeline needed to distribute CO_2 from the large point sources to their selected storage reservoirs as calculated by the model. In this Reference Case scenario, this amounts to some 79,000 miles (127,000 km) of dedicated CO_2 pipeline, or an average of about 41 miles (70 km) per source-reservoir pair. Also, the table indicates the average annual recovery of oil and gas due to EOR and ECBM response resulting from these 10 years' worth of CO_2 injection as modeled for this scenario. Results indicate that an average annual recovery of 726 million barrels of oil and some 3 trillion cubic feet (85 billion cubic meters) of coalbed methane may be possible.[30] Based on recent production data (EIA 2004) this would represent approximately 22% of current annual oil production and 11% of current annual natural gas production within the U.S. and Canada.

The Reference Case suggests that there are likely some negative cost CO_2 storage opportunities in North America, due to the value of this recoverable oil and gas. However, once the cost of capture is accounted for, the small (i.e., -$7/tonne CO_2) subsidy from the sale of co-produced oil and natural gas will most likely be overwhelmed by the cost of capture. Therefore, CCS systems are unlikely to deploy in the United States and Canada absent a price on carbon or some other explicit disincentive on the free venting of CO_2 to the atmosphere. Should such a signal be sent via a carbon price or some other means, the economies of Canada and the United States appear to have access to a significant amount of CO_2 storage capacity that, at least in the near-term, should cost no more than $12-15/tonne CO_2 to access.

Figure 5.2 presents the results of the Reference Case with the transport and net storage cost components displayed separately along with the resulting combined curve. As this disaggregated curve shows, distinct steps (i.e., price levels) exist within the net cost of storage (which includes any offsetting revenue from recovered hydrocarbons). The transport costs are in essence responsible for smoothing out this step level behavior of the storage costs resulting in the more continuous total transport and storage curve. Also while, for most of the cost curve, the net cost of storage is generally the driving factor in total cost, transport costs become important for some of the smaller and more distant sources towards the far right side of the curve. Additionally, Figure 5.2 suggests that the majority of CO_2 storage capacity can be obtained with minimal transport costs. In other words, a significant portion of this capacity is available within very short distance to the sources – and in many cases is found in formations directly beneath the CO_2 point sources.

[30] These values represent a theoretical average annual oil and coalbed methane recovery response, for the life of the project. Actual EOR and ECBM recovery does not follow a linear response to CO_2 injection, and the injection of 10-years worth of captured CO_2 would likely be performed over a longer timeframe, perhaps up to 30 years, depending on the field-level characteristics and operational management strategy employed. Therefore, actual annual recovery will not be constant, and will vary from project to project.

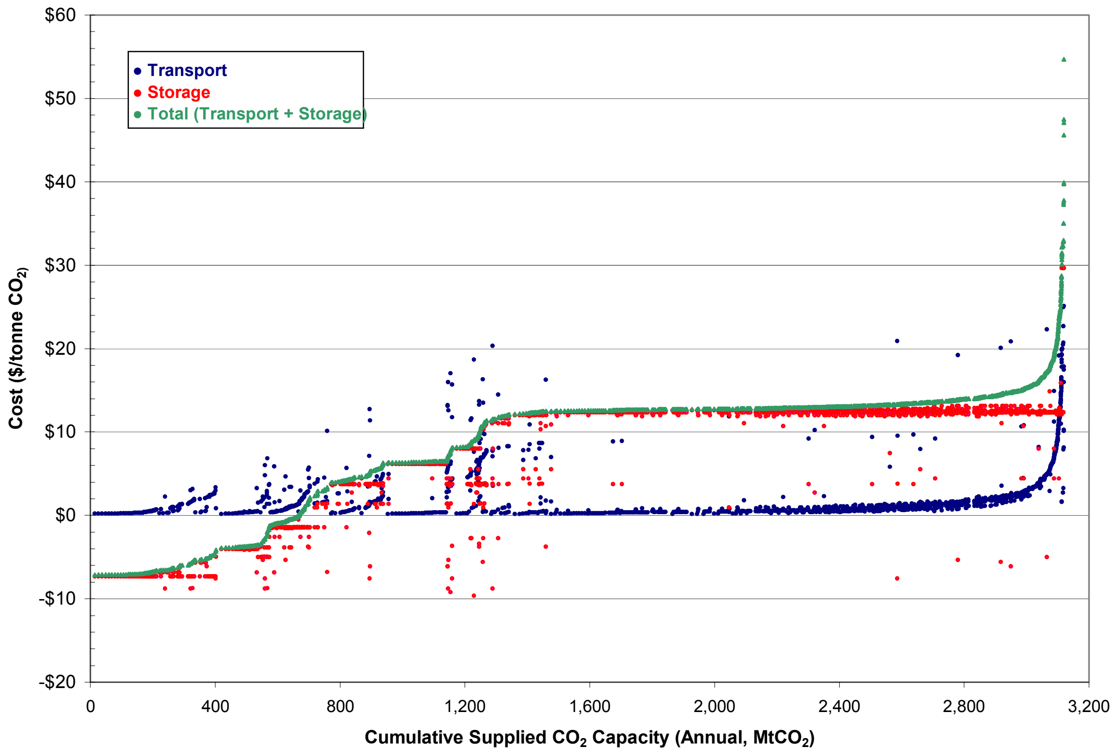

Figure 5.2. Disaggregated CO_2 Storage Supply Curve for North America for the Reference Case

5.3 Sensitivities

There are a myriad of factors that come to bear on the ultimate cost of transporting and storing a tonne of CO_2, including reservoir-specific properties such as reservoir geometry, porosity and permeability, and the uncertainties associated with these types of measurements. As better data become available, the generalizations made in this analysis can be replaced with more precise formation-specific data on these types of quantities to more thoroughly explore the impact that these quantities have on ultimate storage cost. Here, however, sensitivities are examined that relate to the pairing procedure and key cost assumptions.

5.3.1 Search Radius

First, varying the search radius from the Reference Case value of 100 miles (161 km) enables examination of the assumption that 100 miles is a reasonable maximum pipeline length for most of the large CO_2 point sources in North America. For this sensitivity, search radii of zero miles and 250 miles (402 km) were examined. In the Zero-Mile Case, sources were only allowed to access formations that underlie the point source.[31] In the 250-Mile Case, sources were allowed to select formations up to 250 miles from the source using the same cost-minimizing assumptions presented in the Reference Case, and based on the same assumptions regarding allocation of available capacity.

As can be seen from the data presented in Table 5.2 for the Zero-Mile Case, 2,505 $MtCO_2$ of capacity is supplied to sources, representing 77% of total annual available post-capture CO_2. This is 616

[31] However, as discussed in Section 4.3.2, even with a zero-mile search radius, the transport model assumes that a minimum pipeline distance is required in order to locate a suitable injection site and to distribute the CO_2 within an injection field.

$MtCO_2$ capacity less than is supplied when sources are allowed to seek out reservoirs up to 100 miles away. The zero-mile curve is essentially composed of only those sources that lie directly above a storage formation, so this means that 77% of CO_2 emissions in North America overlie a potential storage formation with sufficient capacity. In this case, however, 45 sources, representing roughly 2% of available CO_2, are stranded because their candidate reservoir(s) are filled before the source has a chance to inject within that formation. In this Zero-Mile Case, there is 877 $MtCO_2$ of storage capacity in value-added formations with costs lower than the threshold costs for DSF/gas formations, about $12 in this case.

Table 5.2. CO_2 Transport and Storage Supply Summary for the Zero-mile Search Radius

Zero-mile Search Radius	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	575	217	484	205	1,481	45
Total Supplied CO_2 Capacity (Mt/yr)	817	757	690	241	2,505	65
Total CO_2 (% of total available CO_2)	25%	23%	21%	7%	77%	2%
Minimum price ($/tonne CO_2)	$12.49	-$7.13	$12.16	-$6.61	-$7.13	
Maximum price ($/tonne CO_2)	$14.88	$12.43	$15.46	$31.28	$31.28	
Total pipeline in use (miles)	6,728	2,539	5,663	2,399	17,329	
EOR Recovery (MMBO/yr)					648	
ECBM Recovery (Bcf/yr)					2,016	

As can be seen from Table 5.3, 3,213 $MtCO_2$ of capacity is available to sources under the 250-mile (402-km) scenario. This represents the storage capacity required to store 98% of the total annual captured CO_2 from all of the major North American point sources.[32] Yet, this is only 92 $MtCO_2$ more supplied capacity than is available in the 100-mile scenario, and results in a more than three-fold increase in total pipeline distance, to over 261,000 miles (420,000 km). Because sources can go farther to access value-added formations, however, this larger search radius results in sources accessing more low-cost storage capacity; in fact, an additional 124 $MtCO_2$ of capacity is supplied at costs below the threshold DSF/gas cost (which is the same $12 as in the both the 100-mile and Zero-mile cases). Figure 5.3 compares the cost curves for these three different search radii scenarios, with all other parameters otherwise equal to those of the Reference Case.

Table 5.3. CO_2 Transport and Storage Supply Summary for the 250-mile Search Radius

250-mile Search Radius	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	921	457	422	230	2,030	7
Total Supplied CO_2 Capacity (Mt/yr)	1098	1270	568	277	3,213	16
Total CO_2 (% of total available CO_2)	34%	39%	17%	8%	98%	0.5%
Minimum price ($/tonne CO_2)	$12.49	-$7.13	$12.16	-$6.61	-$7.13	
Maximum price ($/tonne CO_2)	$63.33	$50.37	$31.39	$36.86	$63.33	
Total pipeline in use (miles)	124,304	61,739	50,688	24,553	261,284	
EOR Recovery (MMBO/yr)					718	
ECBM Recovery (Bcf/yr)					3,326	

[32] Assuming a CO_2 capture efficiency of 85%

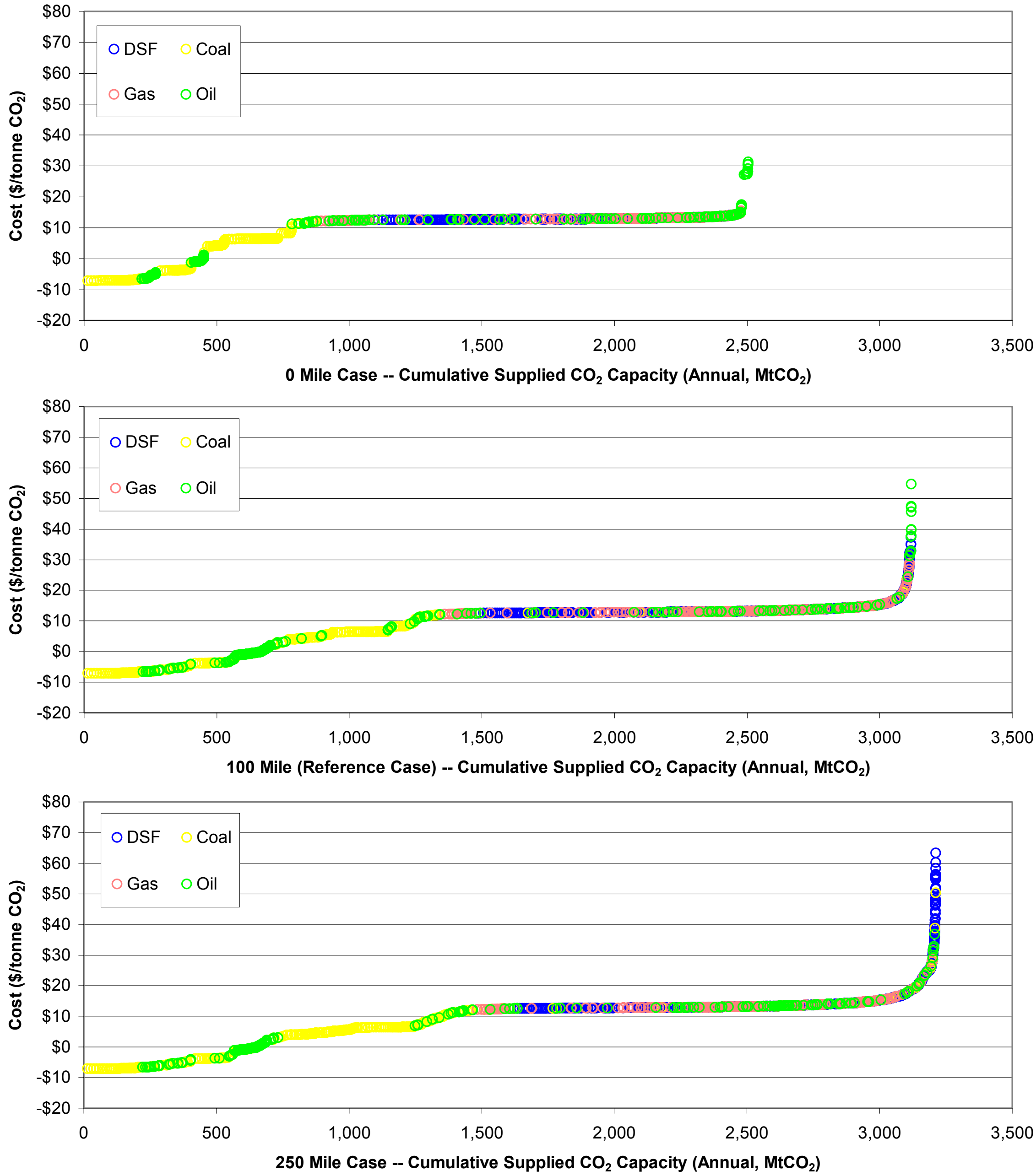

Figure 5.3. CO_2 Supply Curves for North America Assuming Search Radii of 0 miles (top panel), 100 miles (161 km) (Reference Case, middle panel), and 250 miles (402 km) (bottom panel)

5.3.2 Oil and Gas Prices

Because all of the storage capacity available for less than about $12/tonne CO_2 is located in those formations that result in additional incremental recovery of oil and gas associated with the injection of supercritical CO_2, the price of oil and gas can be expected to have a significant impact on the available volume of low cost (i.e., less than $12/tonne CO_2) storage capacity, as well as the total cost range for that available capacity. To evaluate the impact of long-term, sustained oil and gas prices on the transport and injection cost curve, the Reference Case energy price assumptions of $23/bbl and $3.14/mcf, for oil and gas respectively, were varied to both a high and low energy price scenario. The values of oil and natural gas analyzed in the Reference Case and both sensitivity scenarios are summarized by Table 5.4.[33] Figure 5.4 shows the resulting CO_2 storage supply curves under these varying energy price scenarios.

Table 5.4. Oil and Natural Gas Price Assumptions for Reference Case and Price Sensitivities

Scenario	Oil Price ($/bbl)	Gas Price ($/mcf)
Reference Case	23	3.14
Low Energy Prices	15	2.16
High Energy Prices	38	5.13

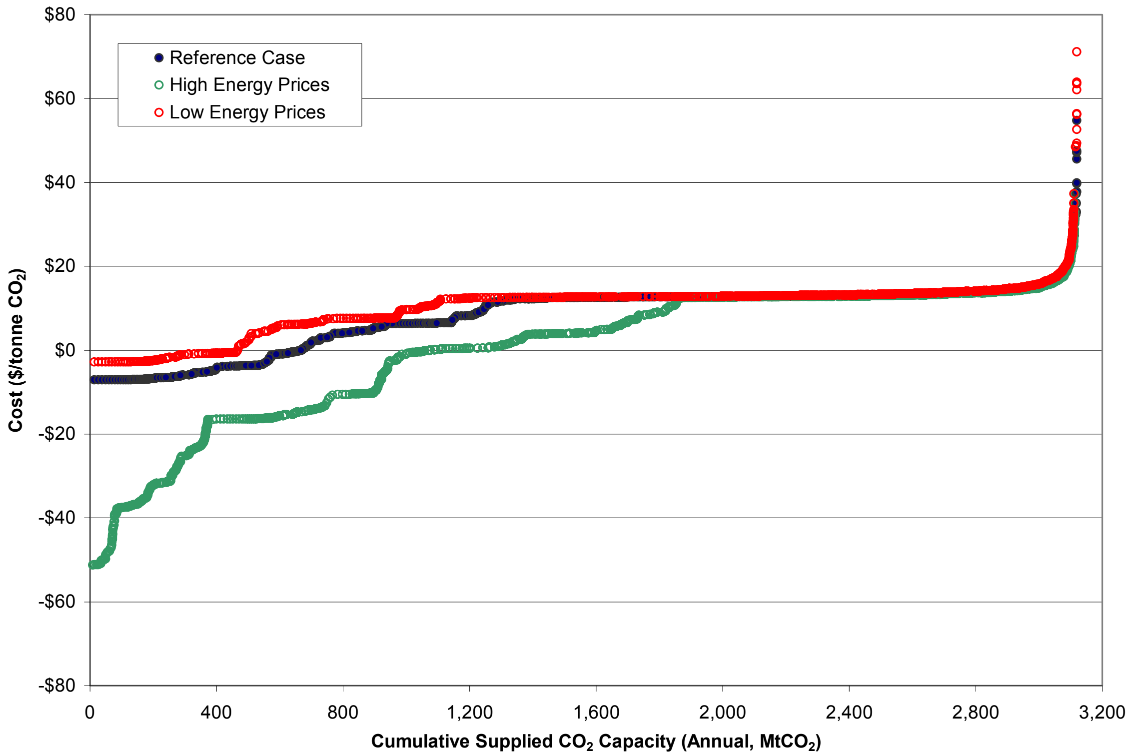

Figure 5.4. North American CO_2 Storage Supply Curves under Various Energy Price Scenarios

[33] Oil prices based on IEO 2003 high/low projections to 2005, assumed to be wellhead prices rather than spot market prices. Gas prices based on IEA GHG's stipulated $2/GJ and $5/GJ less 10.8% adjustment back to wellhead price based on EIA Henry Hub-to-wellhead conversion.

Varying the market price of oil and gas does not impact the total *lifetime* capacity of the value-added (EOR / ECBM) reservoirs in North America. However, as can be seen in Figure 5.4, varying the market price for oil and natural gas does serve to make that capacity more attractive because the increased revenues impact the overall cost, sending a signal to CO_2 sources that causes them to select EOR and ECBM formations preferentially over the larger, costlier DSF and gas reservoirs. These sensitivities, all run for Year Zero and all with a search radius of 100 miles (161 km), show that the change in energy prices simply moves the point at which the deep saline formations and depleted gas formations largely take over the curve; this happens around \$12/tonne CO_2. In the Reference Case, this transition from low cost supplied capacity to the roughly \$12/tonne threshold cost occurs at close to a supplied capacity of 1,300 $MtCO_2$ annually. With lower energy prices, this takes place at around 1,200 MtCO2 annually and with higher energy prices this point is extended considerably to around 1,800 $MtCO_2$.

As can be seen in Table 5.5, lower sustained oil and gas prices result in a 15% decrease in total annually supplied capacity in these lower-cost formations during the first timestep and the overall cost of CO_2 storage shifts upward with a minimum cost of only -\$2.88 per tonne CO_2 (vs. -7.13/tCO_2 for the Reference Case). Sixty-three percent of CO_2 stored in this timestep goes into the non-value-added formations under the low energy price scenario, with the remainder being stored in oil (1%) and coal (34%) formations. In this case, 0.3% of the CO_2 with at least one storage option is left stranded. As the price of oil and gas drop, there is less incentive for CO_2 sources to build long pipelines to reach value-added formations, encouraging them to take advantage of the significant DSF and depleted gas field storage resources that, more often than not, exist directly beneath their plants. As a result, the total pipeline length built to reach reservoirs drops from 79,000 miles (127,000 km) in the Reference Case to 65,000 miles (105,000 km) under the low energy price assumption, representing a decrease of 18%.

Table 5.5. CO_2 Transport and Storage Supply Summary for the Low Energy Prices Scenario

Low Energy Prices Case	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	920	378	576	50	1,924	20
Total Supplied CO_2 Capacity (Mt/yr)	1,165	1,118	805	33	3,121	11
Total CO_2 (% of total available CO_2)	36%	34%	25%	1%	95%	0.3%
Minimum price (\$/tonne CO_2)	\$12.49	-\$2.88	\$12.16	\$10.69	-\$2.88	
Maximum price (\$/tonne CO_2)	\$37.27	\$30.33	\$31.39	\$71.17	\$71.17	
Total pipeline in use (miles)	33,246	15,674	13,290	2,449	64,659	
EOR Recovery (MMBO/yr)					52	
ECBM Recovery (Bcf/yr)					3,047	

As can be seen in Table 5.6, the high energy price scenario reveals a different picture, although with the same underlying motivations. Increasing the price of oil and gas enhances the revenue from value-added storage, and drops the net annual per-tonne cost for transport and storage to a minimum of -\$51.25/tonneCO_2. Under this assumption, 38% of the total annual supplied storage capacity is available at a cost of less than \$12/tonne CO_2, all of which is found in depleted oil and gas-bearing coal formations; a total of 1,854 $MtCO_2$ is available under the \$12 DSF/gas threshold. Under this case, only 39% of the total CO_2 demand is met by DSF and gas storage reservoirs, with 36% in gas-bearing coals, and 21% in oil formations, leaving 0.5% stranded due to lack of sufficient storage volume for 33 sources.[34] In this case, the total amount of pipeline needed in this initial timestep is 95,088 miles, an increase of 20% over the Reference Case. This is the result of a *de facto* incentivization of storage in value-added formations which causes sources to seek out value-added formations farther away, rather than utilizing nearer DSF and gas formations, as a result of the cost-minimizing source-reservoir pairing methodology.

Table 5.6. CO_2 Transport and Storage Supply Summary for the High Energy Prices Scenario

High Energy Prices Case	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	682	359	334	536	1,911	33
Total Supplied CO_2 Capacity (Mt/yr)	805	1,162	450	697	3,114	17
Total CO_2 (% of total available CO_2)	25%	36%	14%	21%	95%	0.5%
Minimum price (\$/tonne CO_2)	\$12.51	-\$16.50	\$12.34	-\$51.25	-\$51.25	
Maximum price (\$/tonne CO_2)	\$37.27	\$20.16	\$31.39	\$15.03	\$37.27	
Total pipeline in use (miles)	32,248	15,577	11,350	35,913	95,088	
EOR Recovery (MMBO/yr)					1,626	
ECBM Recovery (Bcf/yr)					3,298	

5.3.3 EOR/ECBM Production Infrastructure

One of the assumptions included in the Reference Case is that significant infrastructure associated with the production of oil and gas as a result of CO_2 injection (in enhanced oil and coalbed methane recovery operations) would need to be accounted for along with the substantial capital costs involved. However, in some areas of North America, such as the Permian Basin of West Texas, USA, CO_2 is being injected into mature fields with a vast number of production wells already in place, in good operating condition. In these cases, the Reference Case scenario may inequitably penalize these mature fields by incorporating capital costs that may be too high. In order to evaluate the impact that these infrastructure costs may have on the annual per-tonne cost of CO_2 storage in these types of formations, the assumption of additionality of production infrastructure (Table 4.2 from previous Injectivity Costs section) was removed from the Reference Case, and oil and coal formations were treated much like DSF and gas formations in that injection operations were only required to drill and maintain injector wells. This sensitivity therefore assumes that for each of the prospective value-added storage formations, the necessary production wells are present and in operating condition, such that they may be employed for continued recovery of oil or methane under CO_2 injection with little or no extra costs incurred.

Figure 5.5 shows the Reference Case juxtaposed against the same case after the removal of the requirement to build and maintain the additional infrastructure typically associated with CO_2-driven advanced hydrocarbon recovery (termed the Limited Infrastructure Case). Because the infrastructure costs associated with oil production were much higher than those required for coal formations (5.7:1 ratio for oil versus a 2.5:1 ratio for ECBM), stripping away those costs separates oil and coal formations into largely homogeneous cost classes that dominate the cost curve below the \$12/tonne CO_2 threshold. Omitting the production cost requirement makes oil and coal formations appear *much more attractive* (i.e., less costly) relative to other formation types when compared to the initial Reference Case scenario.

[34] The remaining 138 large point sources, representing 138 Mt of potentially captured CO_2, have no potential storage reservoirs within 100 miles.

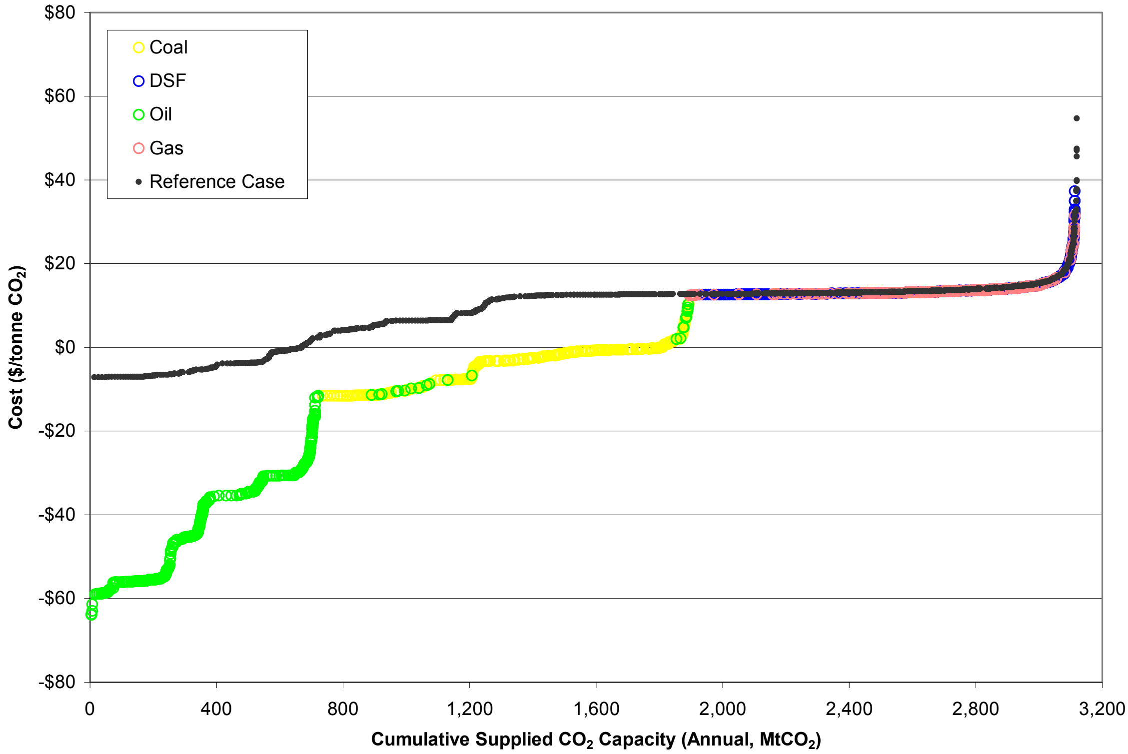

Figure 5.5. North American CO_2 Storage Supply Curves for Reference Case and Limited Infrastructure Case

Note that, from the data in Table 5.7, even the prices for CO_2 transport and storage for some of the EOR and ECBM based opportunities fall above the $12/tonne$CO_2$ DSF/gas threshold. That is, it is not necessarily true that *all* oil and coal formations qualify as "low cost opportunities" when compared to the default cost as defined by DSF and gas formations.[35] As under the high energy prices assumption, more CO_2 gets stored in oil and coal storage reservoirs than under the Reference Case, and more pipeline is required. However, it is interesting to note that, despite a $12.70 decrease in the lowest per-tonne price for storage in oil-bearing formations from the High Energy Prices Case to the Limited Infrastructure Case, this price signal only results in an additional 1% of storage in oil fields, an additional 30 MtCO_2 of additional lower-cost (i.e., <$12/tonne CO_2) capacity, and a relative *decrease* in total pipeline built.

The Limited Infrastructure Case and the Reference Case likely bracket the true costs for most candidate North American EOR and ECBM based storage operations. In some cases, such as those oil fields under current or very recent operation (perhaps just reaching the beginning of their secondary or tertiary recovery period), there will be little need to drill new wells or significantly recomplete existing production wells in a field. The Limited Infrastructure scenario may be of more value in modeling the costs associated with these types of fields. However, in other cases, such as fields honeycombed with old, often unmarked abandoned wells, remediation may be necessary before wells can be rehabilitated or new wells can be drilled for CO_2 injection and storage. This is of particular importance in fields where abandoned, improperly sealed wells may provide conduits for migration of stored CO_2 out of the target formation and into the atmosphere. In this type of field,

[35] This behavior can be seen in most of the scenarios, including the Reference Case, where select depleted oil fields comprise the very highest transport and storage costs.

costs associated with production infrastructure retrofitting, remediation and recompletion could very possibly exceed the costs represented in the Reference Case.

Table 5.7. CO_2 Transport and Storage Supply Summary for the Limited Infrastructure Case

Production Infrastructure Cost Elimination	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	683	390	322	516	1,911	33
Total Supplied CO_2 Capacity (Mt/yr)	782	1,166	439	727	3,114	17
Total CO_2 (% of total available CO_2)	24%	36%	13%	22%	95%	0.5%
Minimum price (\$/tonne CO_2)	\$12.52	-\$11.95	\$12.34	-\$63.95	-\$63.95	
Maximum price (\$/tonne CO_2)	\$37.27	\$16.90	\$31.39	\$13.61	\$37.27	
Total pipeline in use (miles)	24,733	17,800	7,993	32,584	83,110	
EOR Recovery (MMBO/yr)					1,708	
ECBM Recovery (Bcf/yr)					3,352	

5.4 Reservoir Filling and Required Capacity Commitment

CO_2 storage capacity in geologic media represents a finite and heterogeneously distributed natural resource. The formations that are most attractive to sources, particularly the value-added formations that result in a lower net per-tonne cost than formations such as DSFs and depleted gas formations, also tend to be the formations with the lowest relative capacities. Intuitively, this tension between limited supply and strong demand should result in a relatively rapid exhaustion of the value-added classes of this resource. Indeed, even in the first timestep, capacities in some oil and gas formations were exhausted earlier than their non-value-added counterparts as a result of this mismatch between supply and demand.

The previous sections discuss the impact that varying some of the key assumptions in the cost development methodology has on the shape of the curve and its underlying characteristics. However, each of these sensitivities has looked exclusively at a single timestep in the analysis – the annual CO_2 capacity supply curve for the first ten years of CCS deployment across North America. To evaluate how CCS in North America will evolve over time, the impacts of the ten-year timestep and filling constraint on the finite storage resource and deployment of CCS across North America is examined. This section examines the impacts of the selected filling commitment requirement as well as the implications of a longer 20-year minimum requirement.

5.4.1 10-Year Fill Cycle (Reference Case)

Using a ten-year uniform injection cycle (i.e., once a source selects a reservoir, it injects into that reservoir for a full ten years before it is allowed to reevaluate its lowest-cost reservoir choice subject to availability of remaining storage capacity in candidate reservoirs), CO_2 Storage Supply Curves have been produced for each of the following time periods:

- Year Zero: this is the above-mentioned Reference Case, which represents the optimal least-cost solution set for all CO_2 point sources that can find a suitable reservoir within 100 miles during the first decade (years 0 - 9)

- Year 10: the optimal least-cost transport and storage solution set for the second decade (years 10 - 19);

- Year 20: the optimal least-cost transport and storage set for the third decade (years 20 - 29).

These three cost curves are shown together in Figure 5.6. A key observation that one can derive from this figure is that, as time progresses, the "low hanging fruit" is consumed quickly with negative-cost storage opportunities becoming quite scarce after the first timestep.

As can be seen from Figure 5.7, which shows the same curves by selected formation type, most of the low- and negative-cost oil field and coal seam capacity that is filled during the first timestep (Year 0) is replaced by deep saline formations. Therefore, any concern about the cost of storage rising for the economies of Canada and the United States should be tempered by the realization that the large capacity of deep saline formations and depleted gas fields effectively caps the cost of CO_2 transport and storage at no more than \$12 to \$15/tonneCO_2 for most point sources even in these later timesteps.

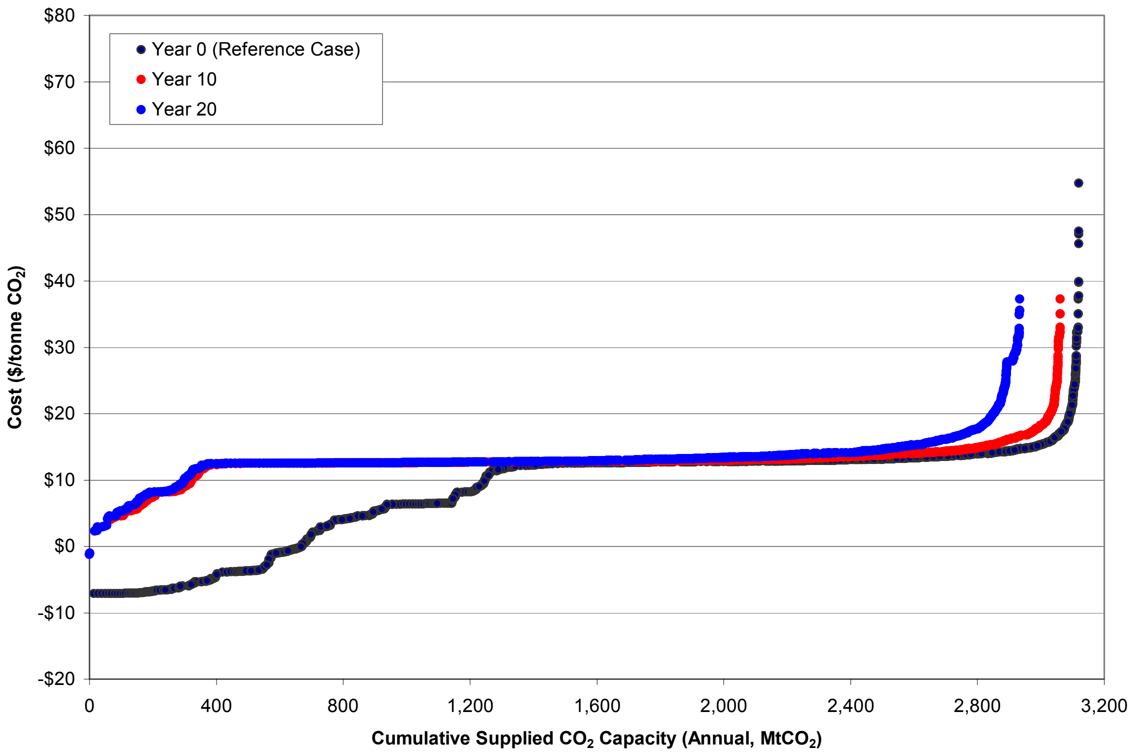

Figure 5.6. North American CO_2 Storage Supply Curves for Year 0, Year 10, and Year 20

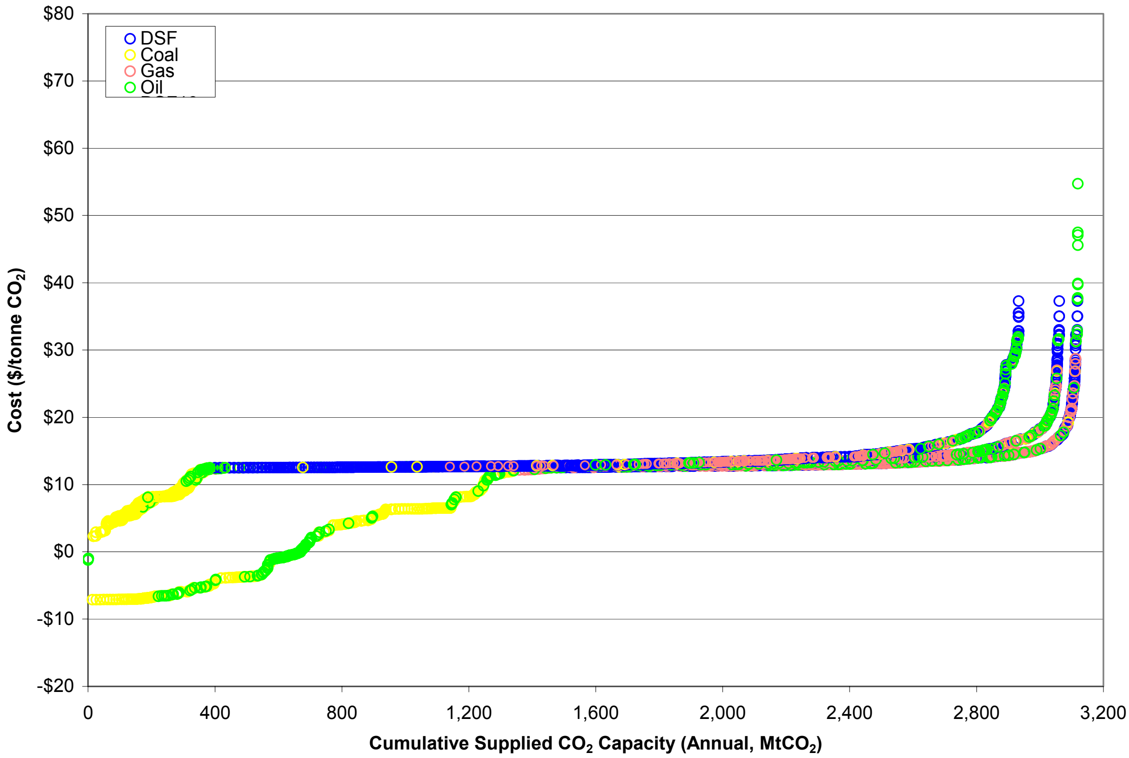

Figure 5.7. North American CO_2 Storage Supply Curves for Year 0 (Right), Year 10 (Middle), and Year 20 (Left) Colored by Formation Type

The effect of storage reservoirs filling over time is shown in Figures 5.6 and 5.7 as well as in Tables 5.8 and 5.9 (note that data for Year 0 are presented in Table 5.1 as this is the Reference Case). The most notable change occurs between the first and second timesteps, i.e., between the Reference Case (Year 0) and Year 10. A significant amount of the value-added capacity available to sources is exhausted during the first timestep, and in years 10 through 19, sources are forced to seek other storage reservoirs. This results in shifting the range of costs from -$7.13 to $54.70/tonne CO_2 in Year 0 to a range of -$1.23 to $37.27/tonne CO_2 in Year 10. As a result of this filling of oil and coal reservoirs, the share of the total produced CO_2 going to these types of formations shifts as well. From Year 0 to Year 10, supplied capacity in coal formations shifts from 36% to 13%, and oil from 9% to 3%. The amount of stranded capacity increases from 0.3% to 2% over the same interval, as some storage formations fill. While storage in gas reservoirs stays relatively static, the amount of CO_2 being stored in DSFs nearly doubles after the first timestep, from 33% to 59%.

The shift from the second to the third timestep is less dramatic, with coal losing just one percent of the total market to 12%, and oil holding relatively steady. The range of prices for transport and storage does not change from the Year 10 to Year 20 time intervals. In this timestep, depleted gas fields drops from 19% to 9% of total supplied capacity, as the smaller and more heavily utilized gas formations fill, and the amount of CO_2 that is stranded due to reservoir filling and search radius constraints triples from 2% in Year 10 to 6% in Year 20.

Table 5.8. CO_2 Transport and Storage Supply Summary for Year 10 (all other assumptions same as Reference Case)

10-year Commitment Case, Year 10	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	1,144	235	378	134	1,891	53
Total Supplied CO_2 Capacity (Mt/yr)	1,915	428	608	110	3,061	70
Total CO_2 (% of total available CO_2)	59%	13%	19%	3%	94%	2%
Minimum price ($/tonne CO_2)	$12.48	$2.31	$12.31	-$1.23	-$1.23	
Maximum price ($/tonne CO_2)	$37.27	$26.84	$31.50	$31.64	$37.27	
Total pipeline in use (miles)	44,486	16,184	14,043	5,001	79,714	
EOR Recovery (MMBO/yr)					353	
ECBM Recovery (Bcf/yr)					1,065	

Table 5.9. CO_2 Transport and Storage Supply Summary for Year 20 (all other assumptions same as Reference Case)

10-year Commitment Case, Year 20	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	1,252	223	264	86	1,825	119
Total Supplied CO_2 Capacity (Mt/yr)	2,142	377	297	116	2,932	197
Total CO_2 (% of total available CO_2)	66%	12%	9%	4%	90%	6%
Minimum price ($/tonne CO_2)	$12.48	$2.31	$12.67	-$1.23	-$1.23	
Maximum price ($/tonne CO_2)	$37.27	$23.55	$31.39	$31.95	$37.27	
Total pipeline in use (miles)	53,755	15,685	8,989	4,968	83,397	
EOR Recovery (MMBO/yr)					576	
ECBM Recovery (Bcf/yr)					1,671	

While these types of shifts may be expected to continue into subsequent decades, the smaller changes in moving from the second to third timesteps relative to the shift from first to second steps hint at an approaching equilibrium. Note how similar the curves for the second and third timesteps appear. The profitable (i.e., <$0/tonne CO_2) opportunities prove to be small and attractive, and this capacity, along with capacity in formations that are accessible to sources for less than the $12/tonne CO_2 threshold cost of DSF and gas formations, are filled quickly. Figure 5.8 illustrates the increasing reliance on deep saline formations as time progresses. It can be concluded from this and the abundant and widespread capacity of deep saline formations that DSFs will likely form the backbone of any long-term CCS deployment scenario in North America.

While the curves in Figures 5.6 and 5.7 represent the modeled utilization of the North American geologic storage resource as a function of time, they do not imply that all or even most of the value-added formations have filled by the end of the first, second, or third decades. Indeed, there are isolated pockets of capacity that are so far from power generation or other carbon-intensive industries that their low- or negative-cost capacity is not demanded by the market due to high transport costs which make nearer, non value-added storage options more attractive in the cost-minimizing decision process. It should therefore not be surprising that not all of the potentially low-cost formations would be exhausted before any other type of formation is used, as it is really the geographic distribution of the candidate storage reservoirs (relative to the region's large CO_2 point sources) that drives selection and timing of storage resource utilization.

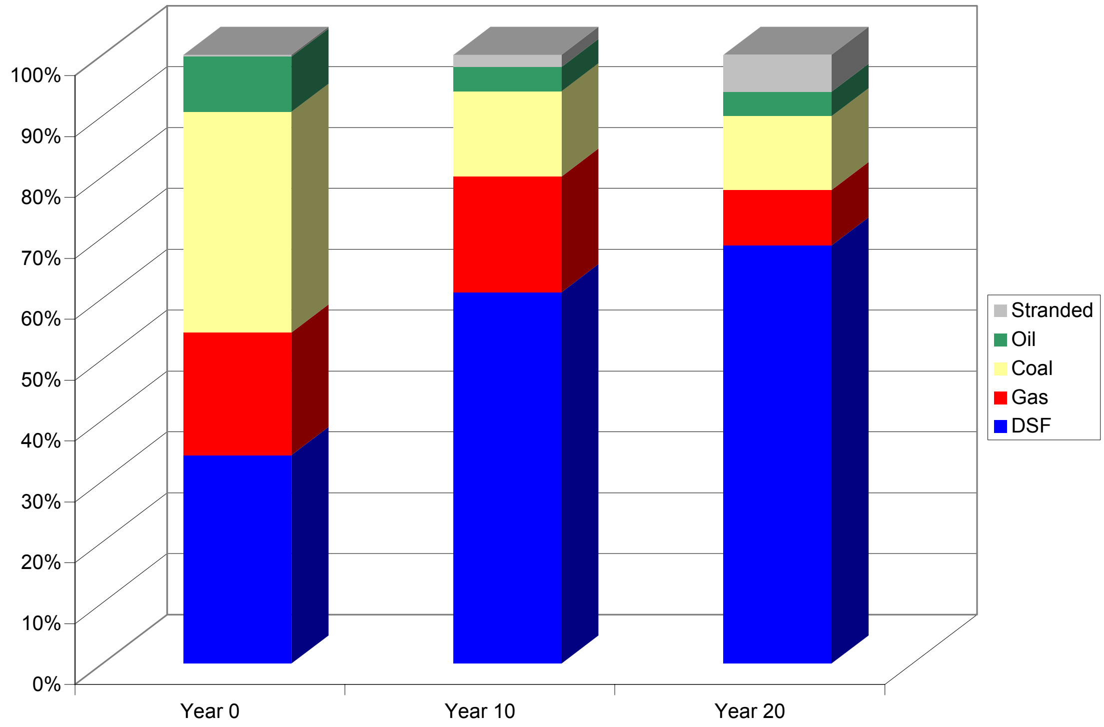

Figure 5.8. North American CO_2 Storage Supply for Year 0, Year 10, and Year 20 Colored by Formation Type

5.4.2 20-Year Fill Cycle

All of the analyses and resulting cost curves discussed to this point have been based on the 10-year filling commitment (or "10-year rule") reservoir capacity constraint. This specifies that a reservoir must be able to store at least ten years' worth of a CO_2 point source's emissions for it to be considered a viable storage option for that source. Consequently, as seen in the previous section, the early filling of some of the low-cost storage capacity indicates that some sources may need to seek out alternative storage reservoirs, and build additional pipeline, after injecting just ten years of their captured CO_2. Here, the impact of increasing this minimum storage capacity requirement to 20 years, i.e., a 20-year rule, is examined. All other assumptions of the Reference Case are otherwise maintained.

Figure 5.9 shows the resulting cost curves for this 20-year storage capacity requirement, for both the initial 20-year timestep (Year 0) as well as the second (Year 20). The summary data for each scenario are contained in Tables 5.10 and 5.11. As can be viewed from the figure, the impact of reservoir filling between the first and second time intervals is similar in nature to that for the 10-year scenarios. Again, low and negative cost storage capacity fills during the initial timestep and gets replaced primarily with capacity in deep saline formations. However, there is a key difference: by requiring candidate storage reservoirs to offer a full 20 years of storage capacity to each prospective CO_2 source, the *available* capacity of the smaller formations is significantly reduced. Compared to the first timestep of the 10-year capacity constraint (i.e., the Reference Case) a full 500 $MtCO_2$/yr of low-cost storage capacity (less than \$12/tCO_2) is bypassed because the reservoirs do not have sufficient capacity to take a full 20 years of CO_2 from nearby sources.

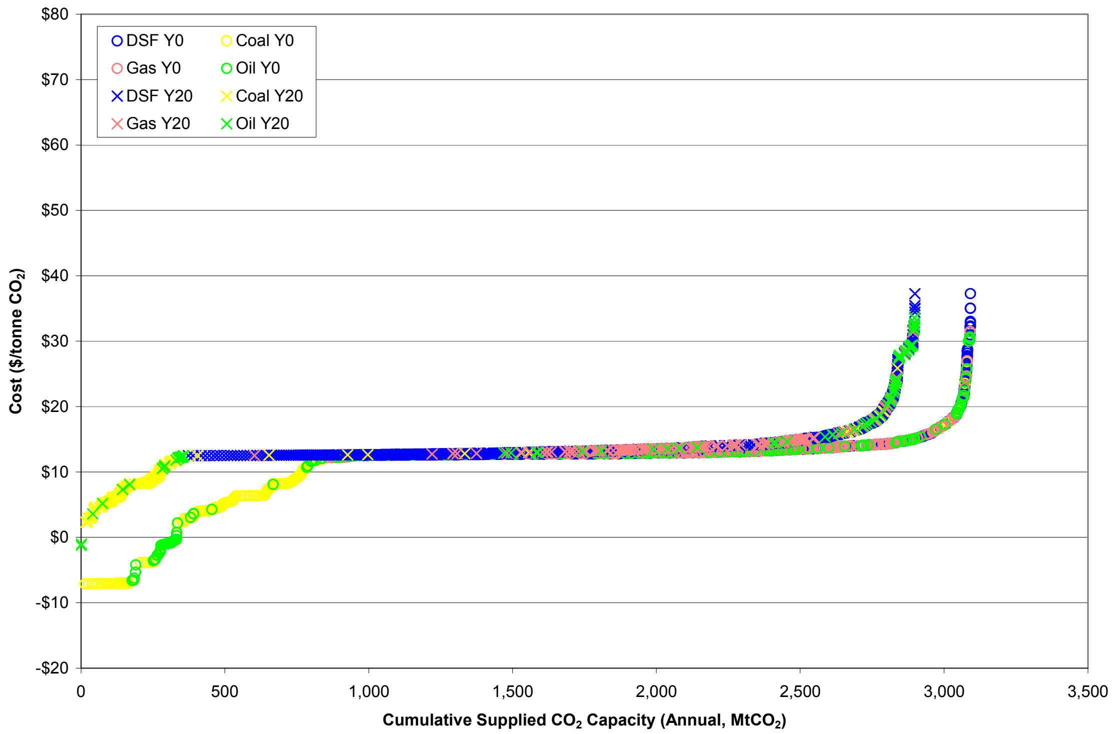

Figure 5.9. North American CO_2 Storage Supply Curves Under the 20-year Rule for Year 0 (Right) and Year 20 (Left) Colored by Formation Type

Table 5.10. CO_2 Transport and Storage Supply Summary for Year 0 of 20-Year Commitment Scenario

20-year Commitment Case, Year 0	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	1,056	273	396	171	1,896	48
Total Supplied CO_2 Capacity (Mt/yr)	1,503	771	639	178	3,091	39
Total CO_2 (% of total available CO_2)	46%	24%	20%	5%	95%	1%
Minimum price ($/tonne CO_2)	$12.49	-$7.13	$12.16	-$6.61	-$7.13	
Maximum price ($/tonne CO_2)	$37.27	$26.84	$31.50	$30.63	$37.27	
Total pipeline in use (miles)	41,320	16,849	14,537	6,320	79,026	
EOR Recovery (MMBO/yr)					441	
ECBM Recovery (Bcf/yr)					1,945	

Table 5.11. CO_2 Transport and Storage Supply Summary for Year 20 of 20-Year Commitment Scenario

20-year Commitment Case, Year 20	DSF	Coal	Gas	Oil	Total	Stranded
Number of Sources	1,278	202	246	81	1,807	137
Total Supplied CO_2 Capacity (Mt/yr)	2,207	359	227	106	2,899	232
Total CO_2 (% of total available CO_2)	68%	11%	7%	3%	89%	7%
Minimum price ($/tonne CO_2)	$12.48	$2.31	$12.53	-$1.23	-$1.23	
Maximum price ($/tonne CO_2)	$37.27	$25.86	$31.39	$33.57	$37.27	
Total pipeline in use (miles)	55,085	13,860	8,186	5,109	82,240	
EOR Recovery (MMBO/yr)					361	
ECBM Recovery (Bcf/yr)					1,288	

Figure 5.10 presents a comparison of the distribution of CO_2 storage capacity supplied by each of the four formations types, as well as the stranded CO_2, under both the 10- and 20-year capacity constraints. As discussed, there is clearly less capacity supplied by coal seams and depleted oil reservoirs within the first timestep of the 20-year commitment scenario versus the 10-year scenario. Coal-based storage drops from 34% to 24% of total supplied storage and depleted oil formations see their share drop from 9% to 5% in the move from the 10-Year Rule Case to the 20-Year Rule Case. Most of this decrease in supplied capacity from value added formations is made up for by DSF-based capacity, as the share of total storage that is supplied by DSFs increases from 33% to 46%. And in this initial timestep (Year 0), three times as much CO_2 is left stranded under the 20-year commitment constraint than under the 10-year constraint, due to the inability of some smaller reservoirs to provide 20 years of CO_2 storage capacity.

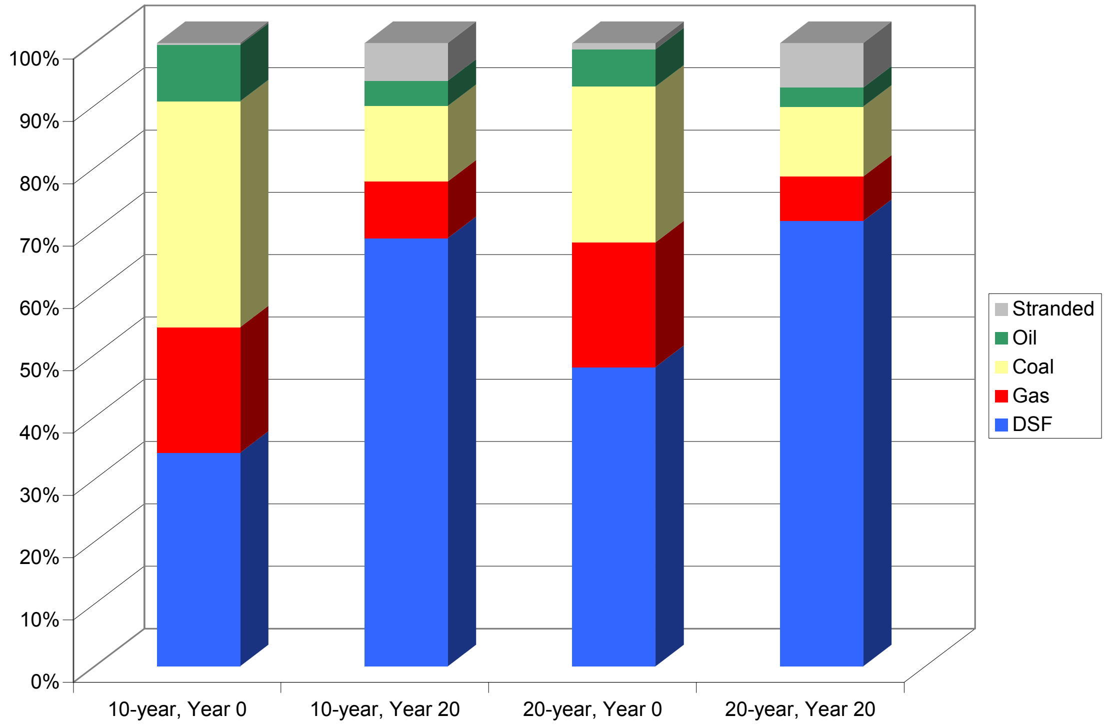

Figure 5.10. North American CO_2 Storage Supply Comparison of 10-Year and 20-Year Capacity Constraints for Year 0 and Year 20 Colored by Formation Type

Examining the Year 20 timesteps for each capacity constraint in Figure 5.10, the supplied storage capacity split by formation type is quite similar. The fraction of total capacity offered by both depleted oil and gas fields in the 20-year constraint scenario is slightly less than under the 10-year constraint (due primarily to there being many of these types of formations with small capacities) but otherwise they are fairly consistent. DSFs account for 66% and 68% of total supplied storage capacity under the 10- and 20-year constraints in Year 20; gas formations make up 9% and 7%, respectively; coal formations 12% and 11%; and oil formations 4% and 3%. For Year 20, the 10-Year constraint leaves 6% of total available CO_2 stranded, while the 20-Year constraint leaves 7% of emissions stranded.

The resulting similarities within this later timestep from the two criteria, despite the disparities within the first timestep (along with the trend noted between Year 10 and Year 20 of the previous 10-year commitment scenario), indicate that, regardless of the filling commitment used in modeling the behavior over time, the North American cost curve will, within the first few decades, approach an equilibrium as value-added capacity is exhausted and sources are forced to seek higher-cost supplies of capacity in DSFs, gas formations, and higher-cost oil and coal fields. In the long run, the U.S. and Canada will likely rely primarily on deep saline formations for their CO_2 storage needs and in general, the cost of accessing these reservoirs should not be expected to exceed \$12 to \$15/tCO_2.

6.0 Lifetime Storage Cost Curves

While the majority of this report has focused explicitly on modeling the competition between CO_2 point sources for the finite storage capacity of candidate geologic formations, the data and tools developed to conduct this analysis also allow for the construction of longer-term "lifetime storage cost curves." In particular, these allow the examination of the shape of the curves considering complete exploitation of all available storage reservoir capacity. To construct these lifetime CO_2 storage supply curves, the cost-minimizing source-reservoir pairing and transport components of the methodology have been set aside. Instead, these curves are developed solely based on each reservoir's computed storage capacity and net cost of storage, including any offsetting revenue from advanced hydrocarbon recovery, and assume that a sufficient supply of CO_2 is provided at the wellhead for injection.

6.1 Aggregate North American Lifetime Storage Cost Curve

Figure 6.1 shows the total lifetime storage supply curve for North America based upon the total cumulative storage capacities of the candidate geologic formations presented in Chapter 3. Each data point on the curve represents an entire formation's CO_2 storage capacity that is available at the calculated cost of storage, ordered from low cost to high. Note again that these costs do not include either capture or transport, but represent only net *storage* costs.

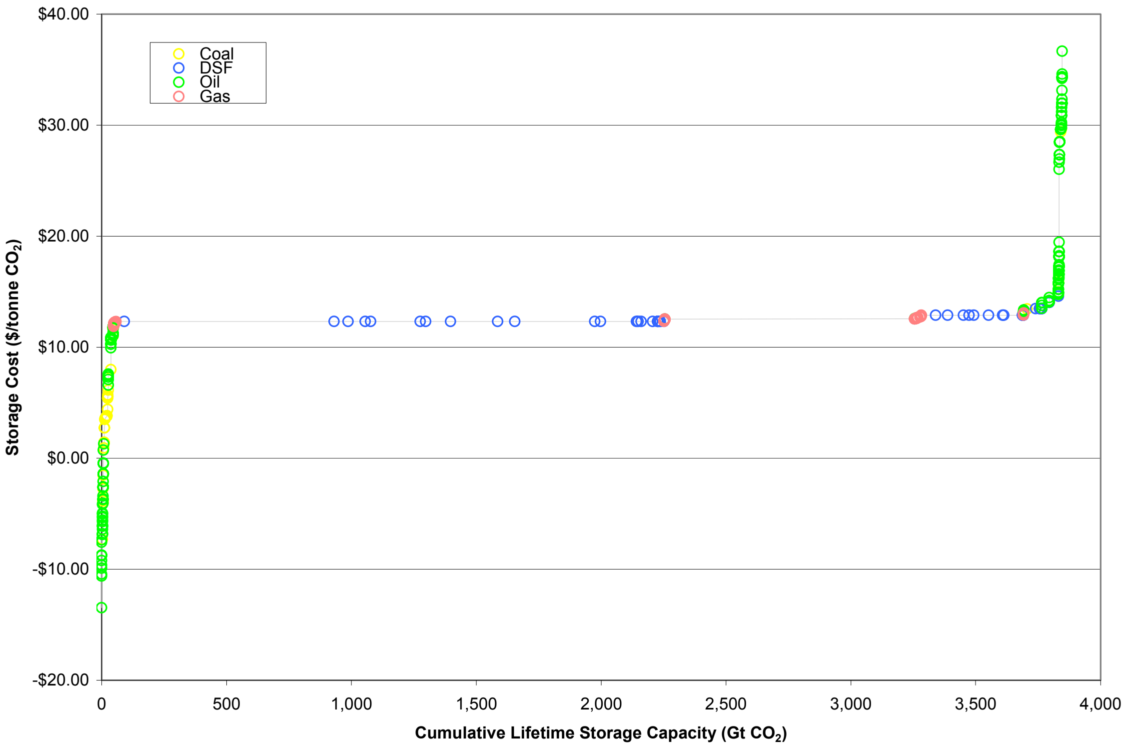

Figure 6.1. Lifetime Storage Cost Curve for North America by Formation Type

Note that, as with curves presented in Chapter 5, this curve consists primarily of three regions: a center plateau at between \$12 and \$15 per tonne CO_2, and two nearly vertical segments on either side of the plateau. And, like the annual curves, the plateau largely comprises deep saline formations. The low cost segment (that portion of the curve closest to the y-axis) is composed of CO_2 storage formations that have the opportunity to generate offsetting revenue associated with CO_2-driven hydrocarbon recovery. Costs in this portion of the lifetime storage curve range from approximately -\$13.50 to \$12.00 per tonne CO_2. The highest-cost storage opportunities tend to correspond to those formations for which depth drives capital and operating costs up, while at the same time low incremental recovery volumes restrict the amount of value-added coproduct that can be sold to offset higher injection costs. Costs for storage in reservoirs along this portion of the lifetime storage curve range from around \$15 to nearly \$37 per tonne CO_2.

Figure 6.1 suggests that, over time, the vast majority of CO_2 storage capacity will be supplied at a storage cost of between \$12 and \$15 per tonne CO_2. In fact, 98% of the more than 3,800 gigatonnes of CO_2 storage capacity shown on this curve falls within this \$12 to \$15 range, comprising primarily DSFs as well as depleted gas formations.

One other notable difference between the lifetime CO_2 storage supply curve presented in Figure 6.1 and the annual CO_2 storage supply curves presented Chapter 5 is illustrated by the large spaces between many of the data points in the central region of the cost curve. This is driven by the juxtaposition of the very large storage capacities of many of the deep saline formations in North America (some of which have hundreds of gigatonnes of CO_2 storage capacity) and the relatively smaller CO_2 storage capacities of oil, gas, and coal formations (many of these having capacities of just a few million tonnes of CO_2). Figure 6.2 helps to further demonstrate the dominant role that deep saline formations are likely to play, and the relative size of these deep saline formations in comparison to the other reservoir classes. Figure 6.2 presents the lifetime storage supply cost curve for each individual class of formation as opposed to the aggregated cost curve presented in Figure 6.1.

6.2 Formation Type-Specific North American Lifetime Storage Cost Curves

Given that there is interest in understanding how cost and storage capacities could vary within in a given class of reservoirs within North America, individual lifetime curves are presented for each formation class, to better illustrate the unique capacity and cost characteristics exhibited by each. In viewing these curves, the reader is asked to note the x-axis scale of each curve, which varies from 12 $GtCO_2$ for oil-bearing formations to 4,000 $GtCO_2$ for deep saline formations.

6.2.1 Deep Saline Formations

The largest fraction of CO_2 storage capacity present in North America is found in deep saline formations. The size of DSFs and the need to make certain simplifying assumptions about these formations due to a lack of detailed data yields a relatively stable cost for storage in these formations. Figure 6.3 shows the lifetime supply curve for North American CO_2 storage in DSFs.

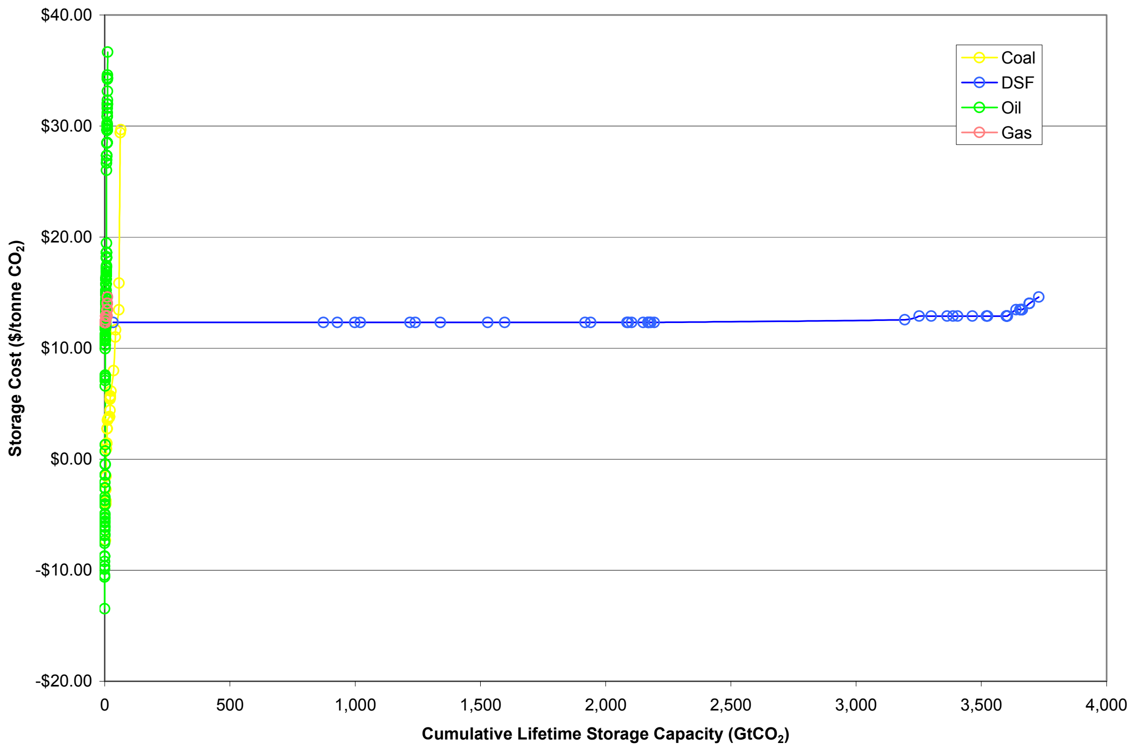

Figure 6.2. Lifetime Storage Cost Curves for North America by Formation Type

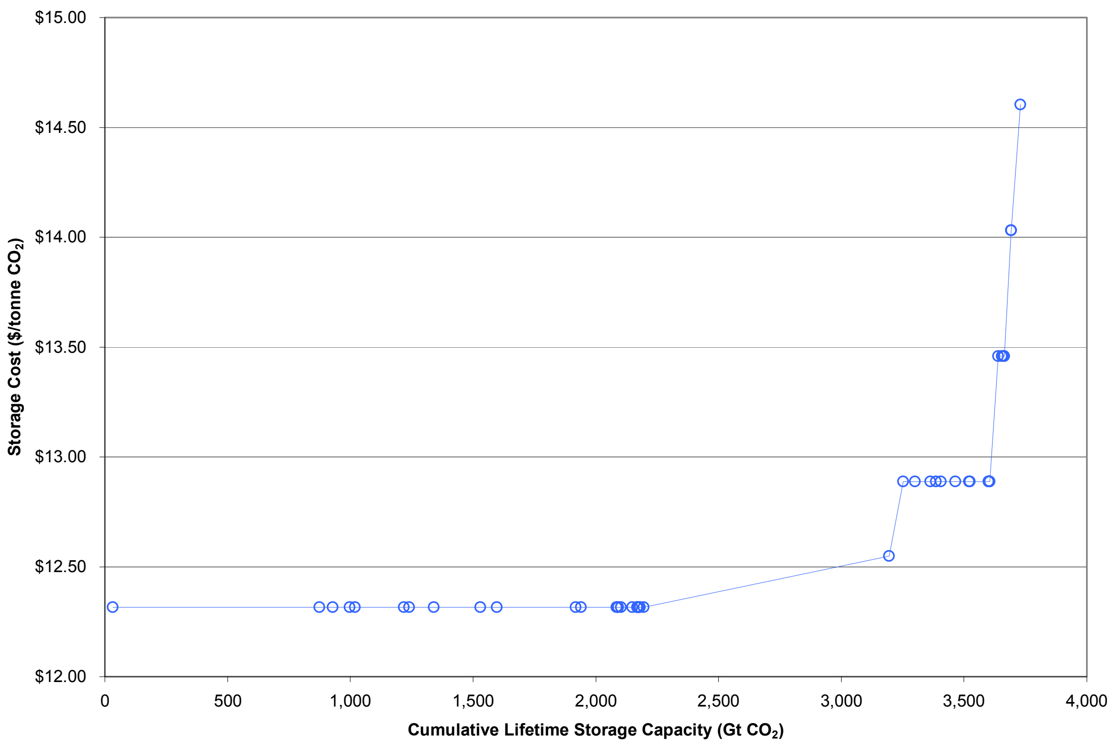

Figure 6.3. Lifetime CO_2 Storage Cost Curve for North American Deep Saline Formations

Differences in cost between individual DSF reservoirs in this analysis were driven entirely by depth. Note that there are six cost levels, corresponding to the six depth categories for these formations. Those DSFs with the lowest cost are also those with the shallowest drill depths (depth category 1). Fifty-nine percent of the total North American DSF capacity is available in this lowest-cost category, and only about two percent of the total DSF capacity falls into the highest two cost classes. Thus, 98 percent of all DSF capacity is available at or between \$12.32 and \$13.46/tonne CO_2, excluding costs associated with capture and transport.

6.2.2 Depleted Gas Fields

In the annual storage cost curves presented previously in Chapter 5, gas formations were intermingled on the curve with the deep saline formations. As with DSFs, this is largely owing to the fact that the differences between storage costs from one formation to the next are driven primarily by depth. However, more detailed formation-specific depths were available for gas basins and therefore the lifetime CO_2 storage supply curve presented in Figure 6.4 shows more continuous variation. As with the DSFs, large jumps along the x-axis represent individual formations with large capacities relative to the smaller formations which tend to cluster more tightly. While a small amount of gas capacity (five percent) is available below \$12/tonne CO_2, the other 95 percent falls within the \$12 to \$15 DSF lifetime price range. Additionally, one-third (33 percent) of all gas capacity is available for less than \$12.50/tonne CO_2 with two-thirds falling between \$12.50 and \$13.09 per tonne CO_2.

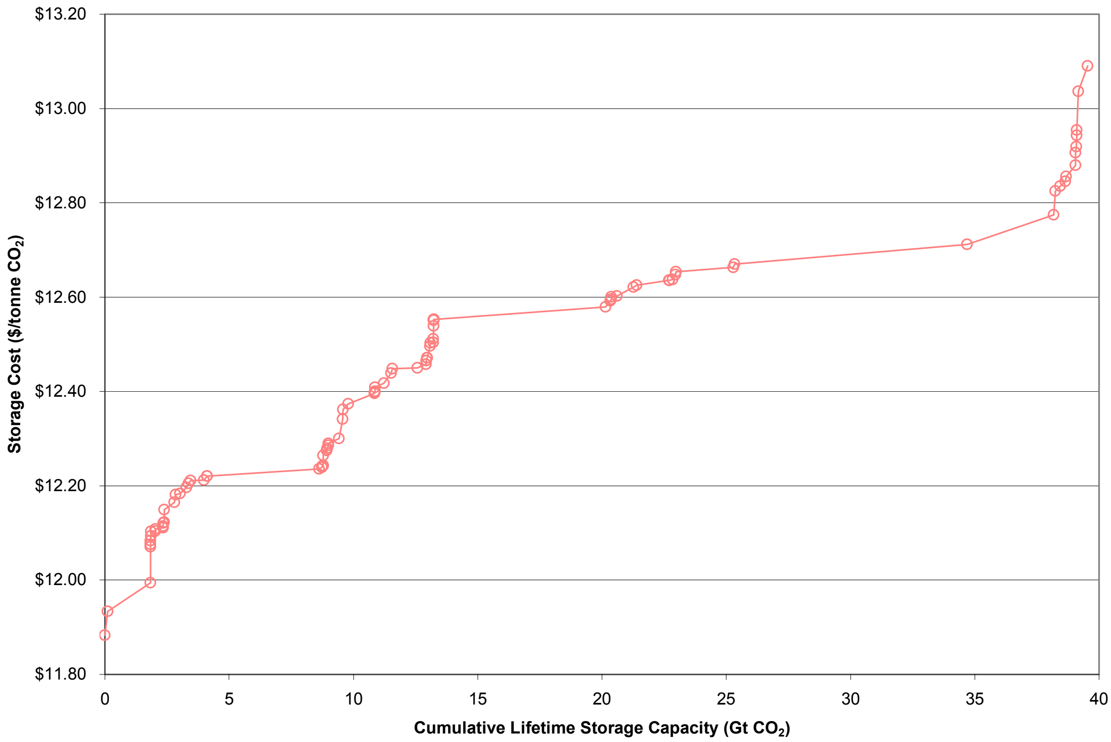

Figure 6.4. Lifetime CO_2 Storage Cost Curve for North American Depleted Gas Fields

6.2.3 Depleted Oil Reservoirs

The formation-specific lifetime cost curve for depleted oil fields, particularly those fields with economics favoring injection of CO_2 for enhanced recovery of incremental oil remaining in the formation after primary production, are of interest because the sale of their value-added coproducts could possibly offset a portion of the costs associated with injection and transport of CO_2. Figure 6.5 shows the lifetime supply curve for storage of CO_2 in North American oil fields.

Under the conditions and oil price applied within the Reference Case, there is roughly two gigatonnes of CO_2 storage capacity available in oil fields for costs of less than \$0/tonne CO_2, or about 18 percent of the total capacity found in North American oil fields. Another two gigatonnes of storage capacity is available at a positive cost but below the \$12 to \$15/tonne CO_2 DSF threshold. Thus, there is a total of about four gigatonnes of low- and negative-cost storage available in the North American oil formations included in this analysis. Interestingly, about 52 percent of all North American capacity from oil fields falls above the DSF cost threshold. In general, these tend to be very deep reservoirs (resulting in higher depth-dependent capital and operating costs) with relatively low incremental oil-to-CO_2 recovery rates (resulting in less offsetting revenue from the sale of recovered oil per tonne of CO_2 injected). This represents a very small marginal amount of CO_2 storage capacity that is available at costs exceeding those for DSFs (i.e., >\$15/tCO_2), and as discussed in Chapter 5, these formations are utilized only by sources having no lower-cost storage option within the specified search radius.

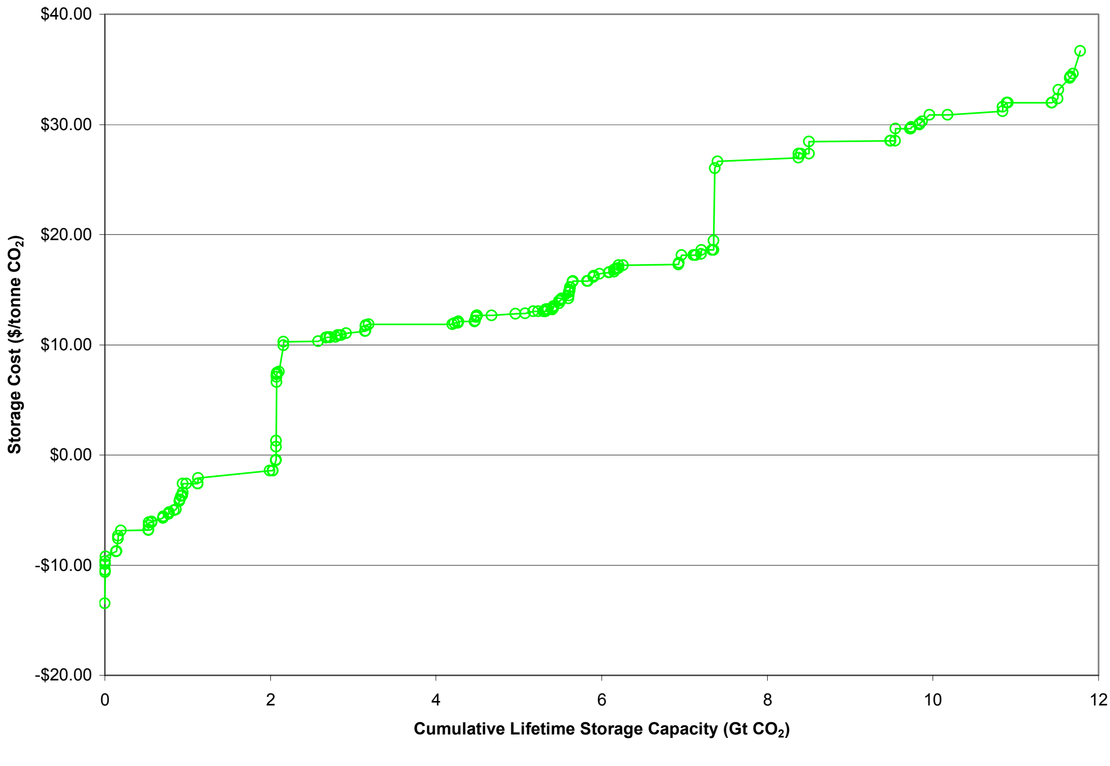

Figure 6.5. Lifetime CO_2 Storage Cost Curve for North American Depleted Oil Reservoirs

6.2.4 Unmineable Coal Seams

In much the same way as oil-bearing formations, methane-bearing coals are of interest because CO_2 injection into these formations has the potential to generate additional revenues that may be used to offset the costs associated with CO_2 storage. Because CO_2 replaces methane adsorbed to the surface of coal in enhanced coalbed methane recovery at different rates for different coals, depending upon thermal maturity and other characteristics, and because this analysis utilized formation-specific depths for coal, costs vary according to a complex combination of these factors and others.

Of the 65 gigatonnes of CO_2 storage capacity available in the North American coal seams evaluated in this analysis and presented in Figure 6.6, five gigatonnes – about eight percent of total coal-based capacity – is available at less than $0/tonne CO_2 (exclusive of capture and transport), approximately half of the proportion of oil capacity available at negative costs. But taking a more expansive view of "low-cost storage capacity" – that is, capacity available below the DSF threshold price of $12/tonne CO_2 – reveals that 67 percent of coal-based capacity (as opposed to 32 percent of oil capacity) is available below the threshold price. This represents 43 $GtCO_2$ of storage capacity, or more than three times the capacity available in *all* North American oil fields. Only twelve percent of coal-based storage capacity, or 8 $GtCO_2$, exceeds the maximum DSF price of $15/tonne CO_2.

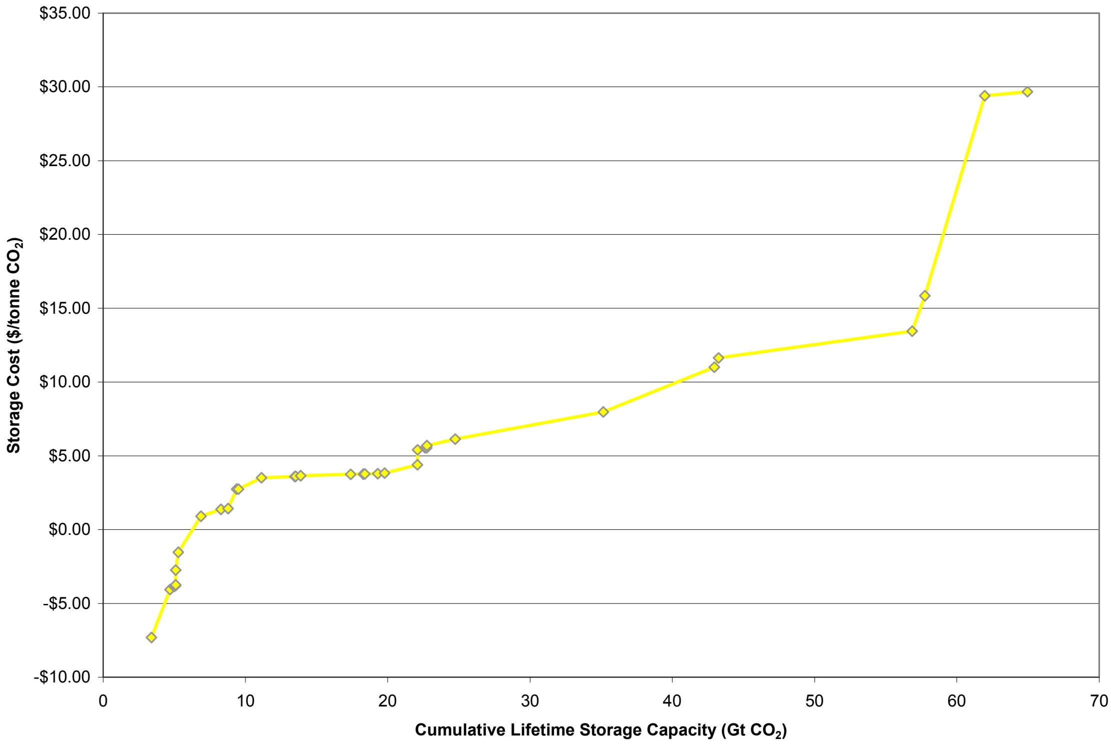

Figure 6.6. Lifetime CO_2 Storage Cost Curve for North American Coal Basins

6.3 Discussion

These lifetime aggregate storage supply curves are most useful as a lens through which to examine what the ultimate storage capacity and long-term cost of CO_2 storage might be within North America. These curves, as well as the shorter-term analyses presented in Chapter 5, suggest that over time, the vast majority of CO_2 storage capacity will be supplied at a storage cost of between $12 and $15 per tonne CO_2. In fact, 98 percent of the more than 3,800 gigatonnes of capacity shown on this Lifetime Storage Supply Curve falls within this $12 to $15/t$CO_2$ range, comprising primarily DSFs. This leaves a comparatively small but nonetheless important amount of capacity available at storage costs both above and below this range.[36] Over the long term, however, costs associated with storage of CO_2 in North America will tend toward this $12 to $15/tonne CO_2 threshold price, as an ever increasing portion of the CO_2 storage load is shifted to deep saline formations.

[36] This remaining 2% of total lifetime storage capacity represents some 70 gigatonnes of potential CO_2 storage capacity that may be very important to the specific regions in which it is located.

7.0 Conclusions

This report documents the results of a two-year research project undertaken by researchers at Battelle and the Alberta Energy and Utilities Board to better understand the potential for CO_2 capture and storage (CCS) systems to deploy in the United States and Canada. From its inception, this research project has been driven by three primary objectives:

(1) the collection and analysis of a significant amount of new data on CO_2 sources and candidate geologic CO_2 storage reservoirs within North America;
(2) the development of a CO_2 storage cost curve methodology that is rigorous and capable of being applied to other regions as source/reservoir data become available; and
(3) the computation of CO_2 storage supply cost curves for North America.

These three objectives were accomplished and this report presents the results of this research.

7.1 Large North American CO_2 Point Sources and Candidate Geologic Storage Reservoirs

The potential market for CCS technologies in North America extends well beyond coal-fired power plants. Within Canada and the United States, this study has identified 2,082 anthropogenic CO_2 point sources, each with annual emissions greater than 100,000 tonnes of CO_2. These 2,082 large CO_2 point sources include:

- 1,156 fossil fuel-fired power plants (accounting for 66% of these point sources' total CO_2 emissions),
- 444 natural gas processing facilities (22%),
- 146 refineries (5%),
- 123 cement kilns (2%),
- 53 iron and steel plants (2%),
- 43 ethylene plants (2%),
- 9 oil sands facilities (1%),
- 40 hydrogen facilities (<1%),
- 25 ammonia plants (<1%),
- 35 ethanol plants (<1%), and
- 8 ethylene oxide plants (<1%).

In total, these facilities represent nearly 4 $GtCO_2$ of annual emissions, with the majority of these point sources (90% of them, accounting for 3.6 $GtCO_2$/year) being located within the United States. The geographic distribution of these 2,082 large CO_2 point sources is shown in Figure 7.1.

So called high-purity CO_2 point sources (e.g., ammonia, ethanol, ethylene oxide, and hydrogen plants) account for less than 1% of CO_2 emissions from the 2,082 large CO_2 point sources considered here. The majority of CO_2 emissions from large CO_2 point sources in North America come from large, low-purity CO_2 point sources such as coal fired power plants.

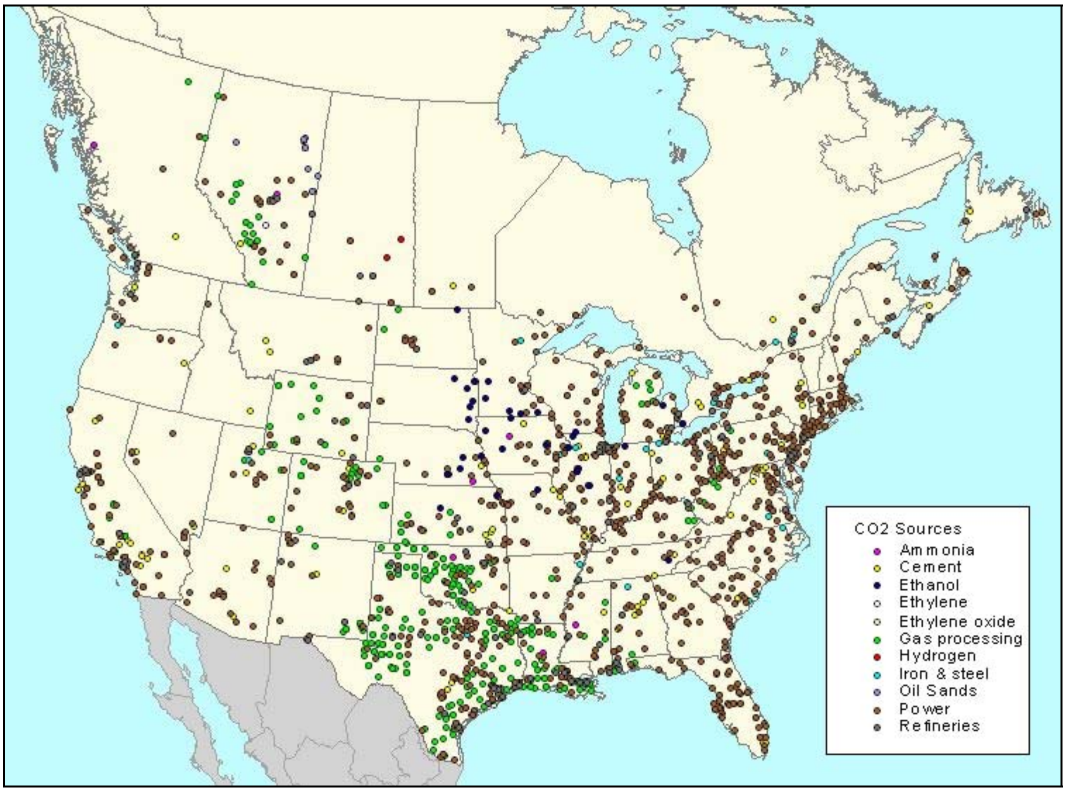

Figure 7.1. Large CO_2 Point Sources in North America

If it should ever become necessary to deploy CCS technologies on a large scale in the United States and Canada, owners of these large CO_2 point sources (and power plants and industrial facilities that have yet to be built) will find that there is a large and varied geologic CO_2 storage potential in North America capable of accepting these units' CO_2 emissions for a considerable period of time. This study has documented a North American geologic CO_2 storage resource consisting of more than 300 onshore candidate geologic reservoirs with a combined storage capacity on the order of 3,800 $GtCO_2$. This very large potential CO_2 storage capacity includes:

- 3,700 $GtCO_2$ of storage capacity in deep saline-filled sedimentary formations (DSF),
- 65 $GtCO_2$ of capacity in deep unmineable coal seams,
- 40 $GtCO_2$ of capacity in depleted gas fields, and
- 12 $GtCO_2$ of CO_2 storage capacity in depleted oil reservoirs with potential for enhanced oil recovery (EOR).

Other types of candidate storage formations have been discussed in the technical literature that may be amenable to current or future CO_2 storage in parts of North America. Most notably, these include deep saline-filled basalt formations, deep black shale formations, and other onshore reservoirs not included in this assessment, as well as off-shore deep saline formations and disused oil fields (such as within Gulf of Mexico and the Atlantic Offshore). Including such formations would add to the already large potential geologic CO_2 storage resource present in North America. Figure 7.2 shows the spatial distribution of the candidate geologic CO_2 reservoirs that were examined in this analysis.

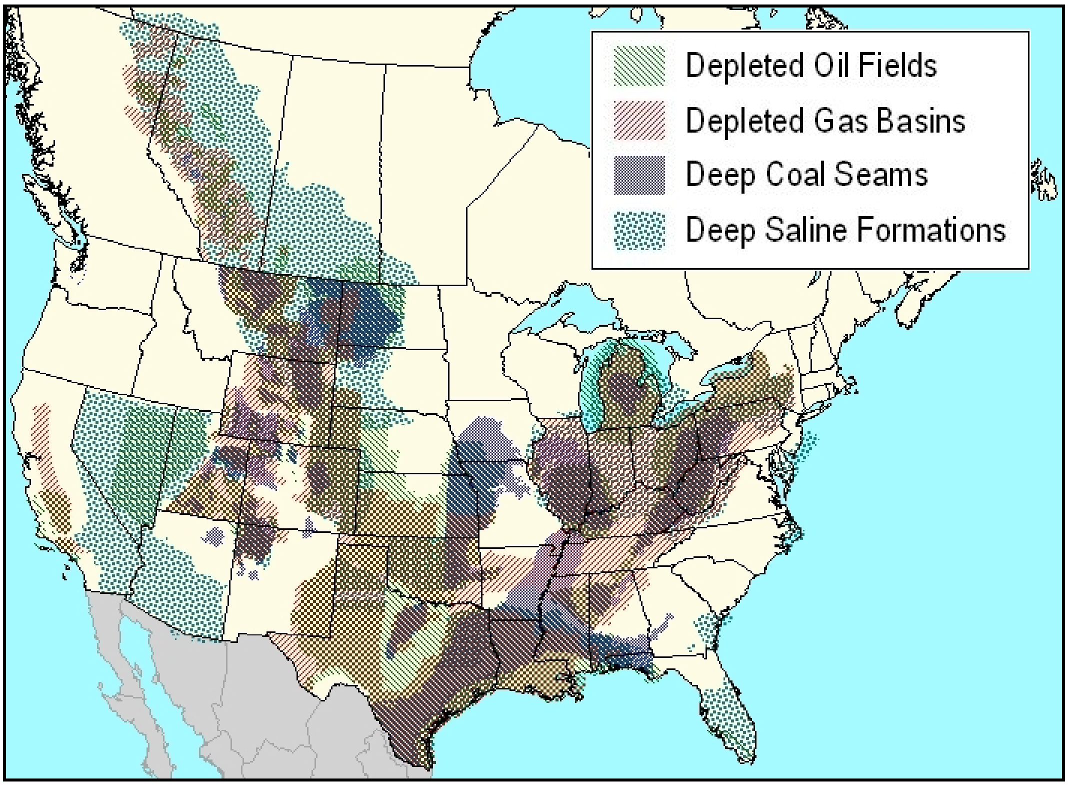

Figure 7.2. Potential CO_2 Storage Reservoirs in North America

Within North America, a relatively small number of large, low-purity CO_2 sources are responsible for the majority of the stationary point source CO_2 emissions. In fact, over 75% of the region's CO_2 emissions from large point sources are attributable to the 500 largest CO_2 emitters. Most of these very large CO_2 point sources are located within close proximity to a potential storage reservoir. 392 of these 500 sources (representing 61% of the region's *total* large point source CO_2 emissions) are located right above a candidate geologic storage formation, and 96% of them (representing 73% of the region's *total* large point source CO_2 emissions) have at least one potential geologic storage option within just 100 miles (161 km). This suggests that CCS has the potential to deliver significant emissions reductions by focusing efforts on the largest sources consisting predominantly of large fossil fuel-fired power plants, gas processing facilities, iron and steel mills, and petroleum refineries.

7.2 Storage Capacity and the Lifetime Storage Supply Curve

The aggregate Lifetime Storage Supply Curves presented in Chapter 6 and repeated here in Figure 7.3 are most useful as a lens through which examine the potential long-term cost of CO_2 storage in North America. These curves, as well as the more detailed analysis presented in Chapter 5, suggest that over time, the vast majority of CO_2 storage capacity will be supplied at a storage cost of between \$12 and \$15 per tonne CO_2, largely from deep saline sedimentary formations. This leaves a comparatively small but nonetheless important amount of capacity available both above and below this range. While this curve does not include transport costs, a large fraction of North American point sources are conveniently located near or atop the formations that provide a large, consistently priced supply of storage capacity. As such, over the long term, costs associated with storage of CO_2 will tend toward this \$12 to \$15/tonne CO_2 threshold price, and as with the decadal cost evolution presented in Section

5.3, over time the trend will be to shift an ever increasing portion of the CO_2 storage load to deep saline formations.

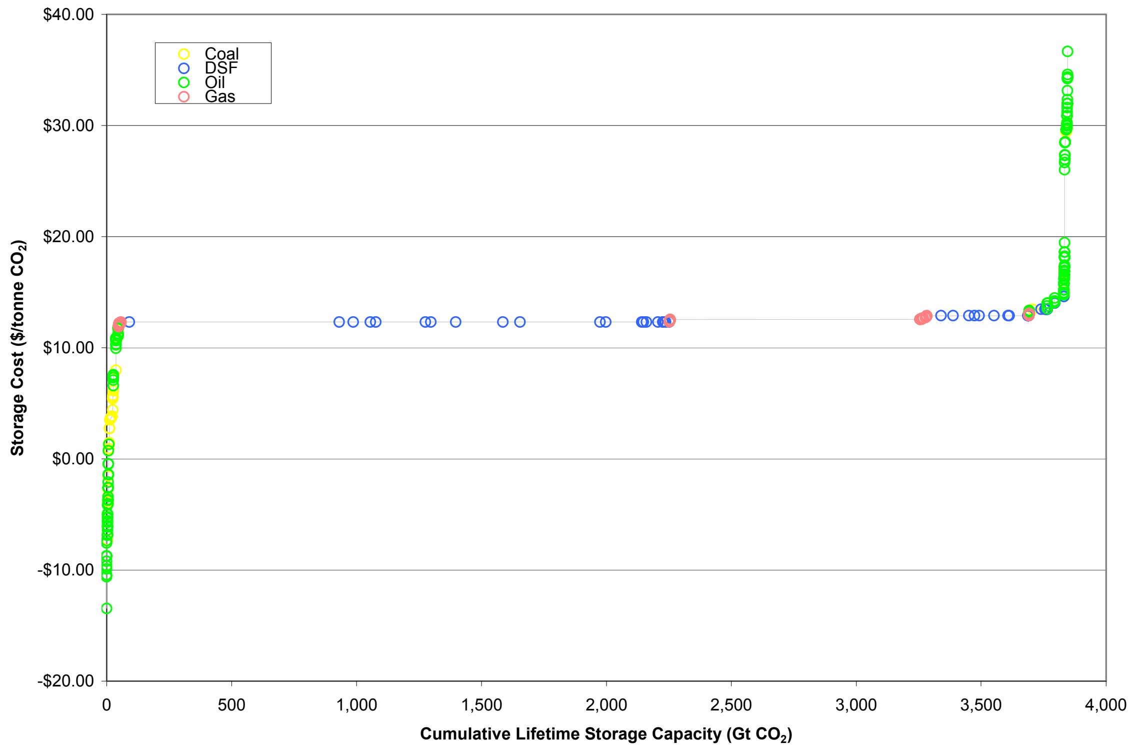

Figure 7.3. Lifetime Storage Cost Curve for North America by Formation Type

7.3 A CO_2 Storage Supply Curve for North America

A key component of this research project was to devise a methodology that would allow for a better understanding of how the market-based demand for CO_2 storage capacity would develop in North America. In order to accomplish this, it was necessary to develop a cost methodology that allowed for the modeling of the interplay between these 2,082 large point sources and the large but finite 3,800 $GtCO_2$ of identified storage capacity. This market-based dynamic between sources *seeking* storage capacity and candidate CO_2 storage reservoirs *offering* storage capacity was represented by an engineering and economic modeling framework that explicitly calculates a series of pairwise cost-minimizing decisions for these CO_2 sources and potential geologic storage reservoirs. This model goes beyond the analysis contained in the Lifetime Storage Supply Curves by explicitly representing the cost of transporting CO_2 from the plant gate to a selected storage reservoir as well as the cost of injecting it into the underground formation, and any offsetting revenue associated with resulting enhanced hydrocarbon recovery. For the purposes of this study, the cost of capture was not considered (i.e., the cost of capture was assumed to be $0/tonne CO_2) to allow for a clearer focus on the storage side of CCS economics. The model employed here also includes rules to ensure that a reservoir's capacity was not oversubscribed, to determine which sources get to access a given reservoir's storage capacity and in what order this access is granted, and to attempt to reflect real world considerations that would likely shape decisions to deploy CCS infrastructure.

Figure 7.4 represents the CO_2 Storage Supply Curve for North America for what is referred to in this report as the Reference Case and represents the potential cost of transporting and storing CO_2 for in a given year during the first timestep (10 years). This curve represents the minimum cost pair for each source and reservoir subject to the boundary conditions of the Reference Case. This Reference Case CO_2 Storage Supply Curve has essentially four major regions:

(1) a negative cost storage region comprised of coalbed and EOR-based storage opportunities, in which the net cost of CO_2 transport and storage could be as low as -\$7 per tonne CO_2 (exclusive of the cost of CO_2 capture);

(2) a region of low but positive cost storage options once again comprised of EOR and coalbed based storage opportunities, where transport and storage costs could be between \$0 to \$12/tonne CO_2;

(3) a large flat section comprised of all of the storage reservoirs but dominated by deep saline reservoirs and depleted gas fields where the cost of CO_2 transport and storage is effectively bounded by a narrow price range of between \$12 to \$15/tonne CO_2; and

(4) a nearly vertical region on the far right of the curve as CO_2 point sources that are just within the 100-mile (161-km) search radius of the Reference Case are able to access a mix of higher-cost storage space, where the cost of CO_2 transport and storage ranges between \$15 to \$55/tonne CO_2.

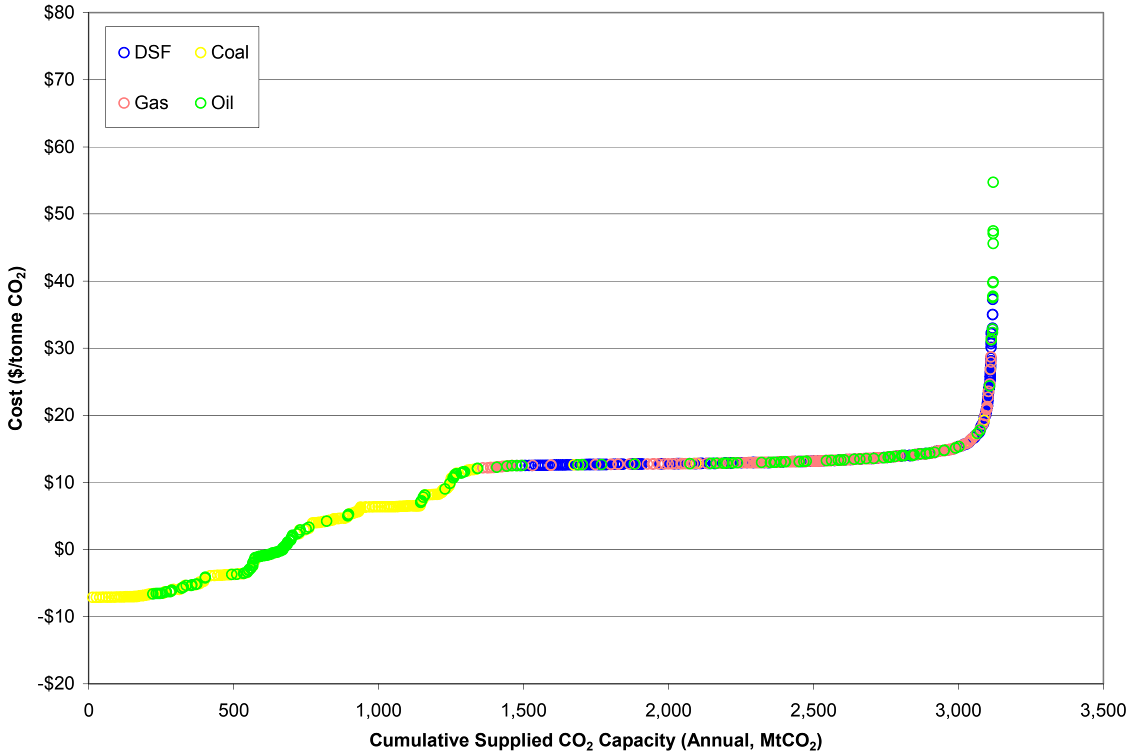

Figure 7.4. CO_2 Storage Cost Curve for North America (Reference Case)

Because CO_2 reservoirs and the large CO_2 point sources that are candidates to employ CCS are neither homogeneous nor evenly distributed across North America, there is a wide spread in potential costs for CO_2 storage. This report documents costs for CO_2 storage (i.e., exclusive of the cost of capture, compression, and dehydration) that potentially span -$7 to $55/tonne CO_2 (a range of $62/tonne CO_2) for the Reference Case, and from -$64 to $71/tonne CO_2 (a range of $135/tonne CO_2) across the various sensitivity cases presented in the body of this report.

The vast majority of CO_2 storage capacity in North America's geologic reservoirs should be available at or below $12-15/tonne CO_2. At some level, a price of $15/tonne CO_2 for the cost of storage might represent an upper bound on the likely costs for those units needing storage capacity in North America, for the remainder of this century and perhaps well into the next.

A significant quantity of CO_2 storage capacity can be accessed for cost less than $0/tonne CO_2. For these formations, the revenue from recovered oil or natural gas resulting from CO_2 injection in depleted oil fields or deep unmineable coal beds is sufficient to offset the cost of building and maintaining the needed CO_2 transport and injection infrastructure and facilities. Depending upon assumptions about the price of oil and natural gas and on the requirement and cost of hydrocarbon recovery infrastructure, there could be between several hundred million tonnes to tens of gigatonnes of negative cost CO_2 storage capacity available in North America. However, it is critically important to note that this study has specifically ignored the cost of capture. Once the cost of capture is factored in, the deployment of CCS technologies will predominantly be a positive-cost activity; i.e., there will need to be an explicit policy mechanism to encourage the reduction of CO_2 emissions to the atmosphere before large scale deployment of CCS technologies would occur in North America.

To the extent that there are low- and even negative-cost storage opportunities, this "low hanging fruit" is likely to be consumed rather quickly (within a decade or two) once large scale use of CCS commences in North America. In particular, because of the high concentration and large number of CO_2 point sources in an area like the Ohio River Valley, low cost storage options (i.e., depleted oil fields and unmineable coal seams offering value-added hydrocarbon recovery) could be consumed early on. Fortunately, this region is home to extremely large deep saline formations and over the long-term these formations should be able to satisfy the CO_2 storage needs of this region. On the other hand, the value-added reservoirs in western Canada, the Rocky Mountain region and Great Plains region of the United States, as well as other select areas in the western U.S., have fewer large CO_2 sources nearby to demand their storage capacity. Therefore these regions have the potential to see low-cost storage opportunities persist for longer periods of time.

Higher prices for oil and natural gas will likely have a modest impact on the cost of CO_2 storage for the North American economy as a whole. However, fluctuations in the price of these energy commodities could have a large impact on the economics of individual CO_2 storage projects.

In North America, there appears to be relatively little need for the construction of very long CO_2 pipelines to move CO_2 to suitable reservoirs as 2.5 $GtCO_2$ (or 77 percent of the total annual captured CO_2 from the large North American CO_2 sources considered here) sit directly above candidate CO_2 storage reservoirs. Allowing for pipelines of up to 100 miles (161 km) to connect each source to a suitable storage reservoir enables sources to access another 615 $MtCO_2$ of annual supplied capacity (or a 25% increase over the Zero-Mile Case). Three-quarters of this additional supplied storage capacity (that comes from moving from the Zero-Mile to the 100-Mile Case) is due to CO_2 point sources sending their CO_2 to more distant CO_2-driven advanced hydrocarbon recovery based storage options, suggesting that, at some level, the cost of building a longer pipeline can be offset by potential revenues from oil and gas recovered as a result of CO_2 injection.

CO_2 storage in depleted oil reservoirs and deep unmineable coal seams could potentially represent an important source of domestic hydrocarbon production. If fully exploited to its theoretical maximum, CO_2 storage in these reservoirs could yield an average of 730 million barrels of oil and 3 trillion cubic feet of natural gas per year under the Reference Case within the U.S. and Canada. This represents approximately 22% of current combined annual crude oil production and 11% of the annual natural gas production of the U.S. and Canada (EIA 2004).

7.4 Final Comment about CCS Deployment in North America

This report presents the results of an economic study of the geologic CO_2 storage potential of North America and how this natural resource might be accessed by various large CO_2 point sources if there were a decision to broadly deploy CCS systems to reduce CO_2 emissions to the atmosphere. As such, it is a modeling exercise based upon a set of scenarios. It is not a prediction of what will happen. If and when CCS systems begin to deploy in North America, the deployment of this class of technologies will be influenced by a number of issues that, while not addressed in the present economic analysis, are nonetheless important. These include, among others:

- Environmental regulations and industry best practices for building, operating, and long-term monitoring of CCS systems have yet to be written. In particular, measurement, monitoring, and verification standards (including how the issue of possible leakage of CO_2 back to the atmosphere will be addressed) are not yet defined, making it currently difficult to estimate any costs associated with these yet-to-be written rules.

- Many of the reservoirs (and perhaps more precisely the land that lies above these reservoirs as well as the geologic formations surrounding the target reservoirs) may provide other competing uses. For example, environmental or land-use considerations such as densely populated areas, ecologically sensitive areas, or national park land, may exist on the surface above reservoirs assumed in this analysis to be used for CO_2 storage. Similarly, important water, mineral, or fossil energy resources may be contained within adjacent geologic formations. How these other uses and potential constraints compete with (or compliment the use of) these formations as long-term repositories for CO_2 is not known at this time, and will need to be assessed, both in general and on a site-specific basis in anticipation of and conjunction with CCS deployment.

8.0 Future Research

This report is the result of a first-of-its-kind analysis to understand the economic utilization of candidate CO_2 storage reservoirs in the United States and Canada. As such, it has certain limitations (largely related to data availability), and signals new areas that appear to be ripe for further exploration. These issues are grouped here thematically and where appropriate, mechanisms for addressing these issues are suggested.

8.1 CO_2 Point Source Data

- Continue to refine and update the global database of large CO_2 point sources, including the overall coverage of existing and planned facilities, the spatial resolution of locations and coordinates, and emissions stream data quality (output and concentrations). Specific attention should be paid to certain industrial sectors whose emissions are based on older data, such as cement (for which the latest emission estimates are derived from 1996 production data), and refineries (1999 data). Special focus should be placed on improving the overall data for sour gas processing plants in the United States, particularly to account for the varying CO_2 content of reservoirs in different gas provinces across the country (currently the same CO_2 content is applied to all locations). The U.S. Department of Energy's (USDOE) Regional Carbon Sequestration Partnership program (USDOE 2004) is likely to be a source of more refined data on many CO_2 point sources in the United States and a few of the key Canadian provinces.

- Catalog data on current industrial and commercial utilization of CO_2 from specific sources so that these volumes of CO_2 can be excluded from CO_2 storage analyses. If there is already an economic use for the CO_2 from these point sources it is likely that such use will continue, precluding this CO_2 from being stored in geologic reservoirs for as long as the economic use persists.

- Determine how to best handle and account for future growth in CO_2 emissions from individual existing plants. That is, for certain long-lived assets, technological shifts or changed economic conditions may lead to growth or decline in CO_2 emissions from current levels as documented in the CO_2 point source database.

- Factor in technological change relating to new CO_2 point sources and develop a methodology for assigning locations for these new facilities. This will be an important component if a CO_2 supply cost curve similar to that presented here is to be developed for regions of the world that are experiencing rapid growth (e.g., China). In rapidly growing economies, the assumption that existing facilities will continue to operate at their current location without making allowances for new facilities could distort the results of the cost curve.

8.2 Modeling of CO_2 Transport

- Develop a framework that allows for the modeling of an interconnected national pipeline network that evolves (i.e., grows) as a function of time as this will more accurately reflect the effective distances and costs required for CO_2 transport infrastructure.

- Allow for the role that CO_2 collection, storage, feeder, and injection systems may play as well as these systems' impact on not only the costs to transport CO_2, but the ability to provide a steady CO_2 supply to multiple injection operations or injection fields located within a given sub-region. This would enable participation by smaller reservoirs that would otherwise be bypassed because they could not hold 10-years' (or 20-years') worth of CO_2 emissions from a point source. Being able to conduct this level of modeling could help to better define the role of the many smaller value-added reservoirs that are quite common in North America.

- Consider a more detailed temporal aspect for this pipeline modeling framework that could examine how pipelines, once built, could be utilized for longer periods of time by, for example, allowing for a small increment of pipeline to be added such that a CO_2 point source may move its injection field to a new injection zone once the current zone within a formation has reached its storage capacity. In the real world, pipelines will be very "sticky" pieces of infrastructure; i.e., once they are built there will be strong pressures to keep them running for a very long period of time.

8.3 Candidate Geologic CO_2 Storage Reservoir Data

- Include a more complete accounting of candidate CO_2 storage reservoirs in North America. This would likely include an assessment of offshore deep saline reservoirs and offshore depleted oil and gas reservoirs (particularly those in the Gulf of Mexico), additional onshore deep saline formations, deep saline-filled basalt flows (see McGrail et al. 2003), black shales (Nuttall and Drahovzal 2004), and other candidate geologic storage reservoirs.[37]

- Expand this analysis to include Mexico, as well as those parts of Canada and the U.S. that were excluded in this first iteration.

- Improve the resolution of data on candidate geologic reservoirs. Much of the data used in the present analysis effectively treats very large geologic formations as if they were uniform across an entire basin. More detailed data at a finer scale of resolution would likely provide a more detailed and precise CO_2 supply cost curve. Once again, the US DOE's Regional Carbon Sequestration Partnership program (US DOE 2004) might be a key source of more refined data on many of the key types of geologic formations examined in this analysis.

[37] This study is focused on CO_2 storage in geologic formations. The methodology here could be extended to also encompass the cost of storing CO_2 in the oceans.

- Examine ways to more accurately assign storage capacity, and therefore transport distance, to localized areas within a large reservoir. Splitting large storage formations into smaller units would enable more accurate modeling of the distribution of storage capacity within these large reservoirs, as well as a better estimation of pipeline costs.

- Screen out areas that are likely unsuitable for geologic storage of CO_2 because of various factors. For example, it seems possible that the CO_2 storage potential of those portions of large basins that lie beneath large cities in North America would remain generally unexploited. Therefore in a finer-resolution analysis of these areas, the storage potential that lies beneath these cities and perhaps areas such as national parks might be excluded. Also, there are a relatively small number of areas in the United States that might be discounted because of concerns related to seismic hazard potential (see for example Davidson et al. 2004).

8.4 Increasing the Resolution of the Cost Curve Methodology

- Develop data on the appropriate technology and costs to capture CO_2 from each of the various types of sources, accounting for the typical flue or process gas composition and pressure.

- Develop methods for allowing point sources to access more than one geologic reservoir at a given point in time. This would help to address the issue of smaller (and in most cases value-added) reservoirs being bypassed because they do not satisfy the "10-year rule" minimum storage capacity requirement.

- Include a more dynamic representation of CO_2-driven enhanced hydrocarbon recovery. This analysis assumed a constant EOR and ECBM incremental recovery rate (as well as a constant rate of CO_2 injection) for all years of injection into a depleted oil field or deep coal seam. However, this is not the case in practice; production response to CO_2 injection is rarely immediate, but rather increases over a number of years before peaking and then declining. This could have a significant impact on the lower end of the cost curves presented here as it might take 30 years to fully inject what is modeled here as "10 years' worth of CO_2" due to project management, water alternating with gas (WAG) injection cycles, and other site-specific issues. Or alternatively, it may be that more injector wells are needed to ensure that there is sufficient injection capacity operating at all times to handle all of a point source's annual CO_2 production. Future iterations of the model used in the present analysis will seek to provide a more robust view of the economics of CO_2 storage in EOR and ECBM fields by better representing the nonlinearity of the respective incremental recovery functions.

8.5 Extending this Analysis to Other Regions of the World

- Initiate analyses similar to those presented here for countries such as China and India which are rapidly growing and which are likely going to represent some of the largest potential markets for CCS technologies during the course of this century.

- Apply the cost curve methodology presented here to regions of the world where comparable data have already been collected such as Australia (see Bradshaw et al. 2003), or in regions where comparable data are currently being collected such as the European Union (Wildenborg et al. 2004) so that more readily comparable regional cost curves could be developed.

9.0 References

Bachu S. 2003. "Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media in response to climate change." *Environmental Geology* 44:277-289.

Bachu S and JJ Adams. 2003. "Sequestration of CO_2 in geological media in response to climate change: capacity of deep saline aquifers to sequester CO_2 in solution." *Energy Conversion and Management* 44:3151-3175.

Bachu S and JC Shaw. 2003. "Evaluation of the CO_2 sequestration capacity in Alberta's oil and gas reservoirs at depletion and the effect of underlying aquifers." *Journal of Canadian Petroleum Technology* 42(9):51-61.

Bachu S and JC Shaw. 2004. "CO_2 storage in oil and gas reservoirs in Western Canada: Effect of aquifers, potential for CO_2-flood enhanced oil recovery and practical capacity." In *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies*, September 5-9, Vancouver, BC, Canada.

Bachu S, JC Shaw, and RM Pearson. 2004. "Estimation of oil recovery and CO_2 storage capacity in CO_2 EOR incorporating the effect of underlying aquifers." *SPE Paper 89340*. SPE/DOE Fourteenth Symposium on Improved Oil Recovery, p. 13, April 17-24, 2004, Tulsa, Oklahoma.

Bondor PL. 1992. "Applications of carbon dioxide in enhanced oil recovery." *Energy Conversion and Management* 33:579-586.

Bradshaw J, G Allinson, B Bradshaw, V Nguyen, A Rigg, L Spencer, P Wilson. 2003. "Australia's CO_2 geological storage potential and matching of emission sources to potential sinks. 2003. Greenhouse Gas Control Technologies." In the *Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies*, eds. J Gale and Y Kaya, pp. 633-644.

Brennan ST and RC Burruss. 2003. *Specific sequestration volumes; a useful tool for CO_2 storage capacity assessment*. U.S. Geological Survey Open-File Report OF 03-0452, p. 12. Availiable at http://pubs.usgs.gov/of/2003/of03-452/.

Brock WR and LA Bryan. 1989. "Summary Results of CO_2 EOR Field Tests, 1972-1987." *Society of Petroleum Engineers, Rocky Mountain Regional Low Permeability Reservoirs Symposium and Exhibition*, p. 499-508. March 6-8, Denver, Colorado.

Brown DR, KK Humphreys, and LW Vail. 1993. *Carbon Dioxide Control Costs for Gasification Combined-Cycle Power Plants in the United States*. PNL-SA-22634, Pacific Northwest Laboratory, Richland, Washington.

Bustin M. 2002. "Research Activities on CO_2, H_2S and SO_2 Sequestration at UBC." *Coal-Seq I Forum*. May 14-15, 2002, Houston, Texas.

Cembureau. 1996. "World Cement Directory." *CEMBUREAU – The European Cement Association*, Brussels, Belgium.

Dahowski RT and JJ Dooley. 2004. "Carbon management strategies for U.S. electricity generation capacity: A vintage-based approach." *Energy* 9(9-10):1589-1598.

Dahowski RT, JJ Dooley, DR Brown, and AJ Stephan. 2001. "Economic Screening of Geologic Sequestration Options in the United States with a Carbon Management Geographic Information System." In the *Proceedings of the Eighteenth Annual International Pittsburgh Coal Conference*. December 4-7, 2001, Newcastle NSW, Australia.

Davidson CL, RT Dahowski, and KP Saripalli. 2004. "Tectonic Seismicity and the Storage of Carbon Dioxide in Geologic Formations." In *Proceedings of the 7th International Conference on Greenhouse Gas Technology.* September 5-9, 2004, Vancouver, B.C., Canada. PNNL-SA-42043, Pacific Northwest National Laboratory, Richland, Washington.

Dooley JJ, CL Davidson, MA Wise, and RT Dahowski. 2004a. "Accelerated Adoption of Carbon Dioxide Capture and Storage within the United States Electric Utility Industry: the Impact of Stabilizing at 450 ppmv and 550 ppmv." In the *Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies (forthcoming)*.

Dooley JJ, SK Kim, JA Edmonds, SJ Friedman, and MA Wise. 2004b. "A First Order Global Geologic CO_2 Storage Potential Supply Curve and Its Application in a Global Integrated Assessment Model." In the *Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies (forthcoming)*.

Dooley JJ and MA Wise. 2003. "Potential Leakage from Geologic Sequestration Formations: Allowable Levels, Economic Considerations, and the Implications for Sequestration R&D." Greenhouse Gas Control Technologies." In the *Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies*, eds. J Gale and Y Kaya.

Doughty C, K Preuss, SM Benson, SD Hovorka, PR Knox, and CT Green. 2001. "Capacity investigation of brine-bearing sands of the Frio Formation for geologic storage of CO_2." *Proceedings of First National Conference on Carbon Capture and Storage*, (CD-ROM) USDOE/NETL-2001/1144, p. 16. May 14-17, 2001, Washington, D.C., United States Department of Energy, National Energy Technology Laboratory.

Edmonds JA, J Clarke, JJ Dooley, SH Kim, SJ Smith. 2004. "Stabilization of CO_2 in a B2 world: Insights on the roles of carbon capture and disposal, hydrogen, and transportation technologies." *EMF 19 Alternative Energy Strategies for Climate Change Policy*, a special issue of *Energy Economics*. July 2004. 26(4): 517-537.

EIA - Energy Information Administration. 2004. *Country Analysis Briefs*. U.S. Department of Energy, Energy Information Administration, Washington, DC. Available electronically at http://www.eia.doe.gov/emeu/cabs/cabsna.html.

Ennis-King J and L Paterson. 2003. "Rate of Dissolution Due to Convective Mixing in the Underground Storage of Carbon Dioxide." In *Proceedings of the Sixth International Conference on*

Greenhouse Gas Control Technologies, eds. J Gale and Y Kaya, pp. 507-510. Elsevier Science Ltd., Kidlington, Oxford, UK.

Fisher L, T Sloan, P Mortensen, and S Bachu. 2002. "Costs for Capture and Sequestration of Carbon Dioxide in Western Canadian Geologic Media." Volume 1: Economics and Suitability of the Basin for Storage, p. 190. Canadian Energy Research Institute, February 2002.

GASIS - Gas Information System. 1999. *A National Database of Geological, Engineering, Production and Ultimate Recovery Data for U.S. Oil and Natural Gas Reservoirs. Release 2*. U.S. Department of Energy, National Energy Technology Laboratory. Available at http://www.netl.doe.gov/publications/press/1997/tl_gasis.html

Gupta N, BM Sass, S Chattopadhyay, J Sminchak, P Wang, and T Espie. 2004. "Geologic storage of CO_2 from refining and chemical facilities in the Midwestern U.S." *Energy* 29(9-10):1599-1609.

Gupta N, P Wang, B Sass, P Bergman, and C Byrer. 2001. "Regional and site-specific hydrogeologic constraints on CO_2 sequestration in the midwestern United States saline formations." In *Proceedings of the 5th International Conference on Greenhouse Gas Control Technologies,* eds .D Williams, B Durie, P McMullan, C Paulson. and A Smith, pp. 385-390. Cairns, Australia. CSIRO Publishing.

Hadlow RE. 1992. "Update of industry experience with CO_2 injection." *SPE Paper 24928*, p. 10.

Hattenbach RP, M Wilson, and KR Brown. 1999. "Capture of carbon dioxide from coal combustion and it utilization for enhanced oil recovery. Greenhouse Gas Control Technologies." In *Proceedings of the 4th International Conference on Greenhouse Gas Control Technologies*, eds. .B Eliasson, P Riemer, and A Wokaun, pp. 217-221. Elsevier Science, New York.

Hawkins JT, AJ Benvgnu, TP Wingate, JD McKamie, CD Pickard, and TJ Altum. 1996. "SACROC Unit CO_2 Flood: Multidisciplinary Team Improves Reservoir Management and Decrease Operating Costs." Society of Petroleum Engineers, Reservoir Engineering, August 1996, pp. 141-148.

Hoffert MI, K Caldeira, G Benford, DR Criswell, C Green, H Herzog, AK Jain, HS Kheshgi, KS Lackner, JS Lewis, HD Lightfoot, W Manheimer, JC Mankins, ME Mauel, LJ Perkins, ME Schlesinger, T Volk, and TML Wigley. 2002. "Advanced Technology Paths to Global Climate Stability: Energy for a Greenhouse Planet." *Science* 1 November 2002; 298:981-987

Holtz MH, PK Nance, and RJ Finley. 1999. "Reduction of greenhouse gas emissions though underground CO_2 sequestration in Texas oil and gas reservoirs." Bureau of Economic Geology, University of Texas at Austin. Final report prepared for EPRI through the U.S. Department of Energy, under Contract No. WO4603-04. Available online at http://www.beg.utexas.edu/environqlty/abndnhydrores/co2text.pdf

Hovorka SD, ML Romero, AG Warne, WA Ambrose, TA Trembley, RH Treviño, and D Sasson. 2000. "Sequestration of greenhouse gases in brine formations." Bureau of Economic Geology, University of Texas at Austin. Available online at http://www.beg.utexas.edu/environqlty/co2seq/dispslsaln.htm.

IEA GHG - IEA Greenhouse Gas R&D Programme. 2002a. *Transmission of CO_2 and Energy*. IEA Greenhouse Gas R&D Programme, Report Number PH4/6.

IEA GHG - IEA Greenhouse Gas R&D Programme. 2002b. *Building the Cost Curves for CO_2 Storage, Part 1: Sources Of CO_2.* IEA Greenhouse Gas R&D Programme, Report Number PH4/9.

IEA GHG - IEA Greenhouse Gas R&D Programme. 2002c. *Opportunities for Early Application of CO_2 Sequestration Technology*. IEA Greenhouse Gas R&D Programme, Report No. PH4/10.

IEA GHG - IEA Greenhouse Gas R&D Programme. 2000. *Barriers to Overcome in Implementation of CO_2 Capture and Storage (1). Storage in Disused Oil and Gas Fields.* IEA Greenhouse Gas R&D Programme, Report No. PH3/22.

IEA GHG - IEA Greenhouse Gas R&D Programme. 1998. *Enhanced Coal Bed Methane Recovery with CO_2 Storage*. IEA Greenhouse Gas R&D Programme, Report No. PH3/3.

Kovscek AR. 2002. "Screening criteria for CO_2 storage in oil reservoirs." *Petroleum Science and Technology* 20(7-8):841-866.

Lindeberg E and P Bergmo. 2003. "The Long-Term Fate of CO_2 Injected into an Aquifer." In *Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies*, eds. J Gale and Y Kaya, pp. 489-494. Elsevier Science Ltd., Kidlington, Oxford, UK.

Marchetti C. 1977. "On geoengineering and the CO_2 problem." *Climate Change* 1:59-68.

McGrail BP, AM Ho, SP Reidel, and HT Schaef. 2003. "Use and features of basalt formations for geologic sequestration." In *Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies*, eds. J Gale and Y Kaya, pp. 1637-1640. Elsevier Science Ltd., Kidlington, Oxford, UK.

Moritis G. 2003. "Kinder Morgan CO_2's Fox: SACROC a 'home run' for company." *Oil & Gas Journal*, May 12, 2003.

Moritis G. 2001. "Future of EOR & IOR: New companies, infrastructure, projects reshape landscape for CO_2 EOR in the US." *Oil & Gas Journal* May 14, 2001.

Myer LR, GM Hoversten, and CA Doughty. 2002. "Sensitivity and cost of monitoring geologic sequestration using geophysics." Poster presented at the *Sixth International Conference on Greenhouse Gas Technologies (GHGT-6)*. October 1-4, 2002, Kyoto, Japan. Available online at http://www-esd.lbl.gov/GEOSEQ/papers.html.

Nuttall BC and JA Drahovzal. 2004. "Analysis of the Devonian Shale in Kentucky for Potential CO_2 Sequestration and Enhanced Natural Gas Production." Paper presented at the *North-Central and Southeast Sections GSA Joint Annual Meeting*, April 4, 2002.

Obersteiner M, C Azar, K Moellersten, K Riahi, J Moreira, S Nilsson, P Read, L Schrattenholzer, Y Yamagata, and J Yan. 2002. *Biomass Energy, Carbon Removal and Permanent Sequestration - A 'Real Option' for Managing Climate Risk*. IIASA Interim Report, IR-02-042, Laxenburg, Austria.

Reeves SR. 2003. "Assessment of CO_2 Sequestration and ECBM Potential of U.S. Coalbeds." Advanced Resources International for the U.S. Department of Energy, February 2003. Available online at http://www.coal-seq.com/Proceedings2003/40924R07.pdf.

Reeves SR. 2001. "Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds: An Integrated Research and Commercial-Scale Field Demonstration Project." In *Proceedings of the First National Conference on Carbon Sequestration*, May 2001.

Renewable Fuels Association. 2003. Webpage listing Ethanol Production Facilities. Accessed December 5, 2003 at http://www.ethanolrfa.org/eth_prod_fac.html.

Riahi K, L Barreto, S Rao, and ES Rubin. 2004. "Towards Fossil-Based Electricity Systems with Integrated CO2 Capture: Implications of an Illustrative Long-Term Technology Policy." In the *Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies (forthcoming)*.

Scott MJ, JA Edmonds, N Mahasenan, JM Roop, AL Brunello, and EF Haites. 2004. "International Emission Trading and the Cost of Greenhouse Gas Emissions Mitigation and Sequestration." *Climatic Change* 60(3):257-287.

Shaw JC and S Bachu. 2002. "Screening, evaluation, and ranking of oil reservoirs suitable for CO_2-flood EOR and carbon dioxide sequestration." *Journal of Canadian Petroleum Technology* 41(9):51-61.

Smith L, N Gupta, B Sass, and T Bubenik. 2001a. *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment, Final Technical Report*. Phase II Report prepared by Battelle for U.S. Department of Energy, National Energy Technology Laboratory, Contract: DE-AC26-98FT40418.

Smith L, N Gupta, B Sass, J Sminchak, C Byrer, and P Bergman. 2001b. "Engineering and Economic Assessment of Carbon Dioxide Sequestration in Saline Formations." In *Proceedings of the First National Conference on Carbon Sequestration,* May 15-17, Washington D.C. Available online at http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/4a3.pdf.

Span P and W Wagner. 1996. "A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa." *Journal of Chemical Reference Data* 25(6):1509-1596.

Taber JJ, FD Martin, and RS Seright. 1997. "EOR screening criteria revisited – Part 1: Introduction, to screening criteria and enhanced recovery field projects." *SPE Reservoir Engineering* 12(3):189-198.

True W. 2002. "Special Report Pipeline Economics: Fed data show solid 2001 for U.S. pipeline companies, more gas capacity planned." *Oil & Gas Journal* 100(38), September 16, 2002. Pennwell Publishing.

Tully J. 1996. *Coal Fields of the Conterminous United States: polygons.* U.S. Geological Survey Open-File Report 96-92. U.S. Geological Survey; Eastern Energy Team. Reston, Virginia. Available online at http://pubs.usgs.gov/of/1996/of96-092/.

United Nations. 1992. Article 2 of the United Nations Framework Convention on Climate Change official website. http://unfccc.int/essential_background/convention/background/items/1353.php

USDOE – U. S. Department of Energy. 2004. Carbon Sequestration - Regional Partnerships. Available online at http://www.fossil.energy.gov/programs/sequestration/partnerships/. Webpage last updated on July 28, 2004.

USEPA – U. S. Environmental Protection Agency. 2002. eGRID version 2.01. Available online at http://www.epa.gov/cleanenergy/egrid/index.htm.

USGS – U. S. Geological Survey. 1996. *USGS Digital Data Series DDS-36: Tabular Data, Text, and Graphical Images in Support of the 1995 National Assessment of United States Oil and Gas Resources*. Compiled by RR Charpentier, TR Klett, RC Obuch, and JD Brewton. Available online at http://energy.cr.usgs.gov/oilgas/noga.

Wildenborg T, S Holloway, C Hendriks, E Kreft, A Lokhorst, M Brook, R Brandsma, P Egberts, and M Larsen. 2004. *Cost curves for CO_2 storage, Part 2: European sector*. Netherlands Institute of Applied Geoscience TNO, Draft Version 2.3. Utrecht, Netherlands.

Appendix A – Large CO_2 Point Sources

The following tables present a summary of the 2,082 large North American CO_2 point sources modeled within this study and discussed in Chapter 2. Table A.1 lists the annual CO_2 emissions, in $ktCO_2$, for each industrial sector, by the state or province in which they are located. Table A.2 is very similar, and lists the number of plants of each type (with annual emissions of at least 100 $ktCO_2$), by state or province. In each case, a rank is provided as the final column, to indicate where each state and province rate when they are all ranked in descending order by total CO_2 emissions and number of plants. In all, there are 59 states and provinces listed, including 10 Canadian provinces and the 48 contiguous United States, plus the District of Columbia.

Table A.1. Summary of Large CO_2 Point Sources by State/Province – Annual Emissions ($ktCO_2$)

State/Province	Country	Ammonia	Cement	Ethanol	Ethylene	Ethylene Oxide	Gas Processing	Hydrogen	Iron & Steel	Oil Sands	Power	Refineries	Total	Rank (of 59)
Alberta	Canada	1,310	1,485		8,697	104	7,480	1,050		26,134	60,733	5,899	112,893	8
British Columbia	Canada	334	536				3,204				4,785	501	9,360	47
Manitoba	Canada		777								1,464		2,241	55
New Brunswick	Canada							140			12,925	2,288	15,353	43
Newfoundland & Labrador	Canada		606					177			2,024	961	3,768	53
Nova Scotia	Canada		434								10,350	809	11,593	45
Ontario	Canada	121	5,411	108	2,176			245	11,845		63,958	5,306	89,170	16
Prince Edward Island	Canada										307		307	57
Quebec	Canada		2,680		600			117	2,149		5,476	3,756	14,777	44
Saskatchewan	Canada							620	125		15,526	2,076	18,347	42
Alabama	US		3,394				18,682		1,786		81,079	1,428	106,370	9
Arizona	US		1,347								47,352		48,699	25
Arkansas	US		804				10,463		249		28,725	485	40,727	33
California	US		7,940				28,209	2,470			56,112	18,533	113,264	7
Colorado	US		1,303				19,885		150		39,767	824	61,928	22
Connecticut	US										10,713		10,713	46
Delaware	US				248			219			5,210	1,464	7,141	49
District of Columbia	US										157		157	58
Florida	US		2,584				506				122,193		125,284	6
Georgia	US		975								78,378		79,353	19
Idaho	US		431								380		811	56
Illinois	US	120	1,961	1,319	1,191			138	1,614		88,268	9,756	104,367	11
Indiana	US		2,422	259					26,383		128,973	4,171	162,208	3
Iowa	US	104	1,935	1,186	953				156		36,694		41,026	31
Kansas	US	298	1,430	215			45,106				37,425	2,784	87,260	17

Table A.1. (continued)

Kentucky	US		474		466		2,309		2,411		93,911	2,139	101,711	12
Louisiana	US	2,271			11,829	454	259,592	919			57,695	26,349	359,109	2
Maine	US		417								3,490		3,907	52
Maryland	US		1,508						4,523		31,606		37,637	34
Massachusetts	US										22,980		22,980	38
Michigan	US		3,461	122			4,214		11,817		73,215	713	93,542	15
Minnesota	US			859				214	2,714		36,131	3,372	43,290	29
Mississippi	US	430	432				15,370	549			22,000	3,169	41,949	30
Missouri	US		3,666	109					125		67,695		71,595	20
Montana	US		627								17,503	1,533	19,662	41
Nebraska	US	206	560	1,088			162				19,662		21,678	39
Nevada	US		477								25,228		25,705	36
New Hampshire	US										4,696		4,696	51
New Jersey	US										18,794	5,472	24,266	37
New Mexico	US		343				49,399				32,693	1,337	83,773	18
New York	US		2,382								59,285		61,667	24
North Carolina	US								125		71,172		71,297	21
North Dakota	US	432		416			991				33,843	1,464	37,146	35
Ohio	US		1,439				101	139	17,435		123,973	5,317	148,405	4
Oklahoma	US	950	1,454				54,012				46,364	2,505	105,284	10
Oregon	US		342						105		7,662		8,109	48
Pennsylvania	US		4,553		492		294		3,190		111,079	7,171	126,779	5
Rhode Island	US										2,684		2,684	54
South Carolina	US		2,312						1,146		37,555		41,013	32
South Dakota	US		581	876							3,873		5,330	50
Tennessee	US		813	177					112		59,165	1,541	61,807	23
Texas	US	1,566	6,425		45,687	701	249,220	1,947	224		250,781	42,279	598,830	1

Table A.1. (continued)

Utah	US		761				5,425		2,827		34,693	1,546	45,252	27
Vermont	US										109		109	59
Virginia	US	581	808						150		42,369	565	44,472	28
Washington	US		948					246			13,822	5,944	20,959	40
West Virginia	US		831				6,158		3,958		85,282	111	96,340	14
Wisconsin	US			109							46,728	320	47,158	26
Wyoming	US		291				52,035				47,401	1,243	100,969	13
TOTAL		**8,723**	**74,360**	**6,842**	**72,340**	**1,259**	**832,818**	**9,187**	**95,319**	**26,134**	**2,544,117**	**175,130**	**3,846,229**	

Table A.2. Summary of Large CO_2 Point Sources by State/Province – Number of Sources

State/Province	Country	Ammonia	Cement	Ethanol	Ethylene	Ethylene Oxide	Gas Processing	Hydrogen	Iron & Steel	Oil Sands	Power	Refineries	Total	Rank (of 59)
Alberta	Canada	4	2		2	1	21	2		9	28	4	73	5
British Columbia	Canada	1	2				3				8	1	15	39
Manitoba	Canada		1								3		4	54
New Brunswick	Canada							1			8	1	10	46
Newfoundland & Labrador	Canada		2					1			3	1	7	50
Nova Scotia	Canada		1								9	1	11	45
Ontario	Canada	1	6	1	2			2	7		26	6	51	10
Prince Edward Island	Canada										1		1	57
Quebec	Canada		4		1			1	1		10	3	20	32
Saskatchewan	Canada							3	1		7	3	14	41
Alabama	US		5				8		4		15	3	35	17
Arizona	US		1				2		1		8	1	17	35
Arkansas	US		2								15		13	42
California	US		10				20	10			105	15	160	2
Colorado	US		3				20		1		20	2	46	11
Connecticut	US										13		13	43
Delaware	US										1		8	49
District of Columbia	US				1			2			4	1	1	58
Florida	US		4				1				58		63	7
Georgia	US		2								21		23	28
Idaho	US	1	3	5	1				1		21		2	56
Illinois	US		1								1		56	9
Indiana	US	1	4	5	1			1	4		34	6	46	12
Iowa	US		4	1					7		32	2	32	19
Kansas	US	2	4	2			10				14	3	35	18

Table A.2. (continued)

Kentucky	US		1		2		3		2	21	1	30	20
Louisiana	US	4			7	2	53	4		35	16	121	3
Maine	US									20		7	51
Maryland	US		3						1	13		17	36
Massachusetts	US		1							6		20	33
Michigan	US		3	1			6		3	30	1	44	13
Minnesota	US			5				1	1	13	2	22	29
Mississippi	US		5	1					1	22		22	30
Missouri	US	1	1				4	1		12	3	29	22
Montana	US		2							5	3	10	47
Nebraska	US								1	27		16	38
Nevada	US	1		1			2			7	1	17	37
New Hampshire	US	1	1	5			1			8		3	55
New Jersey	US									3		30	21
New Mexico	US									26	4	36	16
New York	US		1				22			10	3	57	8
North Carolina	US		2							15		28	24
North Dakota	US		3							54		12	44
Ohio	US		3				1	1	7	28	4	44	14
Oklahoma	US	3	3				65			19	4	94	4
Oregon	US		1						1	5		7	52
Pennsylvania	US		8		1		2		2	48	5	66	6
Rhode Island	US									5		5	53
South Carolina	US		3						2	16		21	31
South Dakota	US		1	6						2		9	48
Tennessee	US		2	1					1	9	2	15	40
Texas	US	4	10		25	5	161	9	1	139	26	380	1

Table A.2. (continued)

Utah	US		2				8		1		8	5	24	26
Vermont	US	1	2						1		24	1	1	59
Virginia	US										1		29	23
Washington	US		2					1			9	6	18	34
West Virginia	US			1							22	1	27	25
Wisconsin	US		1				6		1		18	1	24	27
Wyoming	US		1				25				11	4	41	15
TOTAL		**25**	**123**	**35**	**43**	**8**	**444**	**40**	**53**	**9**	**1,156**	**146**	**2,082**	

Appendix B – Candidate Geologic CO_2 Storage Reservoirs

This appendix provides more detailed information on the candidate geologic CO_2 storage reservoirs considered in this analysis. Each of the following sections presents a labeled map and set of tables for the potential storage reservoirs listing CO_2 capacity as determined by the methods described in Chapter 3. As discussed in Chapter 3, only those candidate storage formations with an estimated capacity of at least 1 $MtCO_2$ have been included.

B.1 Deep Saline Formations

Figure B.1 is a map of North America showing and labeling the major deep saline formations considered in this study. Because most of these formations are very large in areal extent, the U.S. deep saline formations were disaggregated into depth classes, based on the top depth at each point in the formation (as described in Table B.1). As a result, each formation could comprise as many as six classes, five of which (all except Class 0, for which top depth is less than 800 m) would be suitable for CO_2 storage. Thus, individual storage capacities have been estimated for each of the depth classes present within the 21 U.S. DSFs considered here. Data were not available at sufficient resolution to permit similar disaggregation of the Alberta Basin DSF. Resulting capacity estimates, by formation and depth zone, are presented in Tables B.2 and B.3.

Figure B.1. North American Deep Saline Formations

Table B.1. Depth Categories and Intervals for U.S. Deep Saline Formations

Depth Class	Interval Top (m)
0	< 800
1	800-2400
2	2400-4000
3	4000-5600
4	5600-7200
5	> 7200

Table B.2. CO_2 Storage Capacities for U.S. Deep Saline Formations by Depth Zone

Deep Saline Formation / Zone	Capacity ($MtCO_2$)
Arbuckle	**191,050**
Arbuckle – Zone 1	*33,589*
Arbuckle – Zone 2	*57,011*
Arbuckle – Zone 3	*34,449*
Arbuckle – Zone 4	*28,808*
Arbuckle – Zone 5	*37,193*
Basin & Range	**889,055**
Basin & Range – Zone 1	*840,132*
Basin & Range – Zone 2	*48,923*
Cape Fear	**55,684**
Cape Fear – Zone 1	*55,684*
Cedar Keys / Lawson	**69,114**
Cedar Keys / Lawson - Zone 1	*69,114*
Fox Hills	**21,516**
Fox Hills – Zone 1	*21,516*
Frio	**261,774**
Frio – Zone 1	*198,929*
Frio – Zone 2	*62,845*
Glen Canyon	**44,503**
Glen Canyon – Zone 1	*21,501*
Glen Canyon – Zone 2	*23,002*
Granite Wash	**118,572**
Granite Wash – Zone 1	*99,700*
Granite Wash – Zone 2	*18,872*
Jasper	**188,971**
Jasper – Zone 1	*188,971*
Lyons	**142,520**
Lyons – Zone 1	*68,427*
Lyons – Zone 2	*58,717*
Lyons – Zone 3	*15,376*
Madison	**379,968**
Madison – Zone 1	*320,186*
Madison – Zone 2	*56,727*
Madison – Zone 3	*3,055*
Morrison	**26,705**
Morrison – Zone 1	*22,861*

Table B.2. (continued)

Morrison – Zone 2	*3,844*
Mt. Simon	**225,473**
Mt. Simon – Zone 1	*144,334*
Mt. Simon – Zone 2	*75,357*
Mt. Simon – Zone 3	*5,782*
Oriskany	**7,606**
Oriskany – Zone 1	*6,250*
Oriskany – Zone 2	*1,356*
Paluxy	**12,757**
Paluxy – Zone 1	*12,459*
Paluxy – Zone 2	*298*
Lower Potomac	**46,135**
Lower Potomac – Zone 1	*46,135*
Pottsville	**19,202**
Pottsville – Zone 1	*19,202*
Repetto	**2,836**
Repetto – Zone 1	*1,186*
Repetto – Zone 2	*945*
Repetto – Zone 3	*638*
Repetto – Zone 4	*67*
St. Peter	**4,483**
St. Peter – Zone 1	*4,483*
Tuscaloosa	**5,556**
Tuscaloosa – Zone 1	*5,556*
Woodbine	**16,152**
Woodbine – Zone 1	*14,471*
Woodbine – Zone 2	*1,681*
Total U.S. DSF Capacity	**2,729,632**

Table B.3. Deep Saline Formations – Canada

Deep Saline Formation	**Capacity ($MtCO_2$)**
Alberta Basin	1,000,000
Total Canadian DSF Capacity	**1,000,000**

B.2 Depleted Gas Fields

Figure B.2 is a map of the depleted gas basins in North America. As discussed in Chapter 3, U.S. gas data was available at the basin level (as displayed), while the data for Canada were compiled from detailed pool-level reserves databases. These pool-level data were aggregated as described in Chapter 3, and grouped into larger pools as well as to the basin level. The storage capacities for each basin and pool are presented in Tables B.4 and B.5.

Figure B.2. North American Depleted Gas Basins

Table B.4. CO_2 Storage Capacities of U.S. Gas Basins

Gas Basin	Capacity ($MtCO_2$)	Gas Basin	Capacity($MtCO_2$)
Anadarko Basin	9,353	Mid-Gulf Coast	373
Appalachian Basin	1,717	North-Central Montana	110
Arkoma Basin	1,013	Ouachita Folded Belt	7
Bend Arch	175	Palo Duro Basin	89
Big Horn Basin	61	Paradox Basin	14
Black Warrior Basin	312	Permian Basin	3,482
Central Kansas Uplift	15	Piceance Basin	182
Central Western	8	Powder River Basin	15
Chautauqua Platform	115	Sacramento Basin	1,053
Cherokee Platform	72	San Joaquin Basin	146
Cincinnati Arch	4	San Juan Basin	4,500
Denver Basin	224	Sedgwick Basin	267
East Texas Basin	2,324	Southern Oklahoma	221
Fort Worth Syncline	422	Uinta Basin	144
Green River	1,305	Ventura Basin	105
Illinois Basin	33	Western Gulf	6,900
Las Animas Arch	10	Williston Basin	62
Michigan Basin	351	Wind River Basin	200
Total U.S. Gas Capacity			**35,383**

Table B.5. CO_2 Storage Capacities for Western Canadian Gas Basins

Gas Basin / Pool ID	Capacity ($MtCO_2$)
Alberta Basin	**4,156**
Pool 1a	*7*
Pool 1b	*1*
Pool 1c	*5*
Pool 1d	*9*
Pool 1e	*2*
Pool 1f	*398*
Pool 1g	*134*
Pool 1h	*2*
Pool 1i	*2*
Pool 1j	*2*
Pool 1k	*6*
Pool 1l	*532*
Pool 1m	*30*
Pool 1n	*1*
Pool 1o	*1*
Pool 1p	*44*
Pool 1q	*24*
Pool 2a	*7*
Pool 2b	*41*
Pool 2c	*24*
Pool 2d	*12*
Pool 2e	*4*
Pool 2f	*292*

Table B.5. (continued)

Pool 2g	*2*
Pool 2h	*358*
Pool 2i	*3*
Pool 2j	*3*
Pool 2k	*12*
Pool 2l	*117*
Pool 3a	*44*
Pool 3b	*679*
Pool 3c	*9*
Pool 3d	*127*
Pool 3e	*113*
Pool 3f	*6*
Pool 3g	*125*
Pool 3h	*3*
Pool 3i	*13*
Pool 3j	*20*
Pool 3k	*18*
Pool 4a	*200*
Pool 4b	*1*
Pool 4c	*206*
Pool 4d	*64*
Pool 4e	*372*
Pool 4f	*34*
Pool 4g	*43*
Pool 4h	*4*
Total Canadian Gas Capacity	**4,156**

B.3 Depleted Oil Reservoirs

The depleted oil reservoirs in North America that were considered in this analysis are shown in Figure B.3. The map is labeled at the oil province level. However, for both the U.S. and Canada, data were compiled and analyzed at a more detailed level. For Canada, just as for the depleted gas data, capacities for individual oil pools were developed and aggregated as appropriate with nearby pools exhibiting like characteristics (see Chapter 3 for further details). For the U.S., data were developed at the USGS-defined oil play level, and some plays were also combined based on proximity and similarities in depth and oil recovery ratios. Therefore, the map shows oil province outlines (in black) in addition to the green areas showing the specific regions within the provinces determined to offer potential CO_2 storage capacity. Resulting capacities by province and play (for the U.S.) or province and pool ID (for Canada) are listed in Tables B.6 and B.7.

Figure B.3. North American Depleted Oil Basins

Table B.6. Estimated CO_2 Storage Capacity in U.S. Oil Plays

USGS Province Name / Play ID	Capacity ($MtCO_2$)	USGS Province Name / Play ID	Capacity ($MtCO_2$)
San Joaquin Basin	***1,245***	**Palo Duro Basin**	**4**
*Play 1002**	*196*	*Play 4301*	*4*
*Play 1003**	*54*	**Permian Basin**	**3,085**
*Play 1004**	*980*	*Play 4402**	*528*
Play 1006	*10*	*Play 4404**	*665*
Play 1010	*5*	*Play 4407**	*1,009*
Central Coastal	**61**	*Play 4408*	*18*
Play 1106	*34*	*Play 4410*	*864*
Play 1107	*27*	**Bend Arch - Fort Worth Basin**	**173**
Santa Maria Basin	**64**	*Play 4501**	37
Play 1201	*38*	*Play 4505**	*136*
Play 1202	*26*	**Marathon Thrust Belt**	**2**
Ventura Basin	**224**	*Play 4601*	*2*
*Play 1301**	*55*	**Western Gulf**	**1,342**
Play 1302	*139*	*Play 4701**	*231*
Play 1311	*29*	*Play 4705**	*663*
Los Angeles Basin	**554**	*Play 4706**	*68*
*Play 1401**	*62*	*Play 4708**	*113*
*Play 1402**	*286*	*Play 4710**	*90*
Play 1403	*174*	*Play 4715*	*17*
Play 1405	*31*	*Play 4719**	*119*
Play 1407	*1*	*Play 4728*	*40*
Eastern Great Basin	**20**	**Louisiana-Mississippi Salt Basins**	**1,486**
Play 1901	*20*	*Play 4901**	*55*
Uinta - Piceance Basin	**116**	*Play 4905**	*138*
Play 2002	*29*	*Play 4911**	*220*
Play 2005	*87*	*Play 4917*	*6*
Paradox Basin	**76**	*Play 4920**	*973*
Play 2101	*11*	*Play 4930**	*58*
Play 2102	*63*	*Play 4936**	*35*
Play 2106	*3*	**Florida Peninsula**	**26**
San Juan Basin	**21**	*Play 5001*	*26*
Play 2204	*2*	**Cambridge Arch - Central Kansas Uplift**	**14**
Play 2206	*2*	*Play 5305**	*14*
Play 2207	*17*	**Nemaha Uplift**	**231**
North-Central Montana	**17**	*Play 5501*	*173*
*Play 2805**	*15*	*Play 5503**	*57*
Play 2808	*2*	**Forest City Basin**	**1**
Williston Basin	**162**	*Play 5603*	*1*
Play 3101	*82*	**Anadarko Basin**	**318**
*Play 3102**	*66*	*Play 5801**	*18*

Table B.6. (continued)

Play 3106	*13*	*Play 5802**	*179*
Powder River Basin	**317**	*Play 5804*	*7*
*Play 3302**	*94*	*Play 5809**	*60*
*Play 3304**	*99*	*Play 5813**	*46*
*Play 3307**	*96*	*Play 5818*	*3*
Play 3309	*10*	*Play 5827*	*5*
Play 3313	*18*	**Sedgwick Basin**	**6**
Big Horn Basin	**144**	*Play 5901**	*3*
Play 3402	*138*	*Play 5902*	*3*
Play 3406	*7*	**Cherokee Platform**	**330**
Wind River Basin	**37**	*Play 6001**	*330*
Play 3502	*23*	**Southern Oklahoma**	**310**
Play 3503	*2*	*Play 6102**	*67*
Play 3504	*11*	*Play 6103**	*66*
Wyoming Thrust Belt	**49**	*Play 6104**	*13*
Play 3604	*49*	*Play 6108**	*127*
Southwestern Wyoming	**74**	*Play 6109**	*36*
Play 3701	*16*	**Arkoma Basin**	**5**
Play 3702	*3*	*Play 6205*	*5*
Play 3703	*13*	**Michigan Basin**	**98**
Play 3704	*7*	*Play 6301**	*64*
Play 3707	*35*	*Play 6304*	*2*
Park Basins	**2**	*Play 6307*	*32*
Play 3801	*2*	**Illinois Basin**	**127**
Denver Basin	**71**	*Play 6401**	*127*
Play 3901	*5*	**Black Warrior Basin**	**1**
Play 3905	*59*	*Play 6502*	*1*
Play 3907	*4*	**Appalachian Basin**	**6**
Play 3908	*3*	*Play 6706**	*6*
Las Animas Arch	**17**		
*Play 4004**	*17*		
Total U.S. Oil Capacity			**10,832**

Table B.7. CO_2 Storage Capacity in Canada's Oil Pools

Basin Name / Pool ID	Capacity ($MtCO_2$)
Alberta Basin	**508**
Pool 1b	*57*
Pool 1c	*1*
Pool 1d	*5*
Pool 1e	*2*
Pool 1f	*21*
Pool 2d	*1*
Pool 2e	*2*
Pool 5a	*3*
Pool 6a	*22*
Pool 7a	*3*

Table B.7. (continued)

Pool 8a	*3*
Pool 8b	*27*
Pool 8c	*70*
Pool 8d	*1*
Pool 8e	*12*
Pool 8f	*4*
Pool 8g	*1*
Pool 9a	*14*
Pool 9b	*34*
Pool 9c	*2*
Pool 10a	*6*
Pool 10b	*1*
Pool 10c	*4*
Pool 11a	*5*
Pool 11b	*1*
Pool 11c	*3*
Pool 11d	*6*
Pool 11e	*19*
Pool 12a	*5*
Pool 12b	*32*
Pool 12c	*7*
Pool 13a	*90*
Pool 13b	*1*
Pool 13c	*2*
Pool 13d	*1*
Pool 14a	*2*
Pool 14b	*3*
Pool 14c	*2*
Pool 14d	*1*
Pool 14e	*5*
Pool 14f	*8*
Pool 14g	*3*
Pool 15a	*2*
Pool 15b	*2*
Pool 15c	*1*
Pool 16a	*1*
Pool 17a	*2*
Pool 17b	*4*
Pool 17c	*1*
Pool 18a	*1*
Pool 19a	*1*
Williston Basin	**436**
Pool 1a	*420*
Pool 2a	*8*
Pool 2b	*2*
Pool 2c	*3*
Pool 3a	*4*
Pool 4a	*1*
Total Canadian Oil Capacity	**944**

B.4 Coal Seams

Figure B.4 is a map of the coal basins in North America, analyzed for CO_2 storage potential and enhanced coalbed methane recovery. These include 23 separate basins in the U.S. and three coal fields within the Alberta Basin of Canada. For each of the Canadian coals, several individual zones were considered. The estimated CO_2 storage capacity for each are listed in Tables B.8 and B.9.

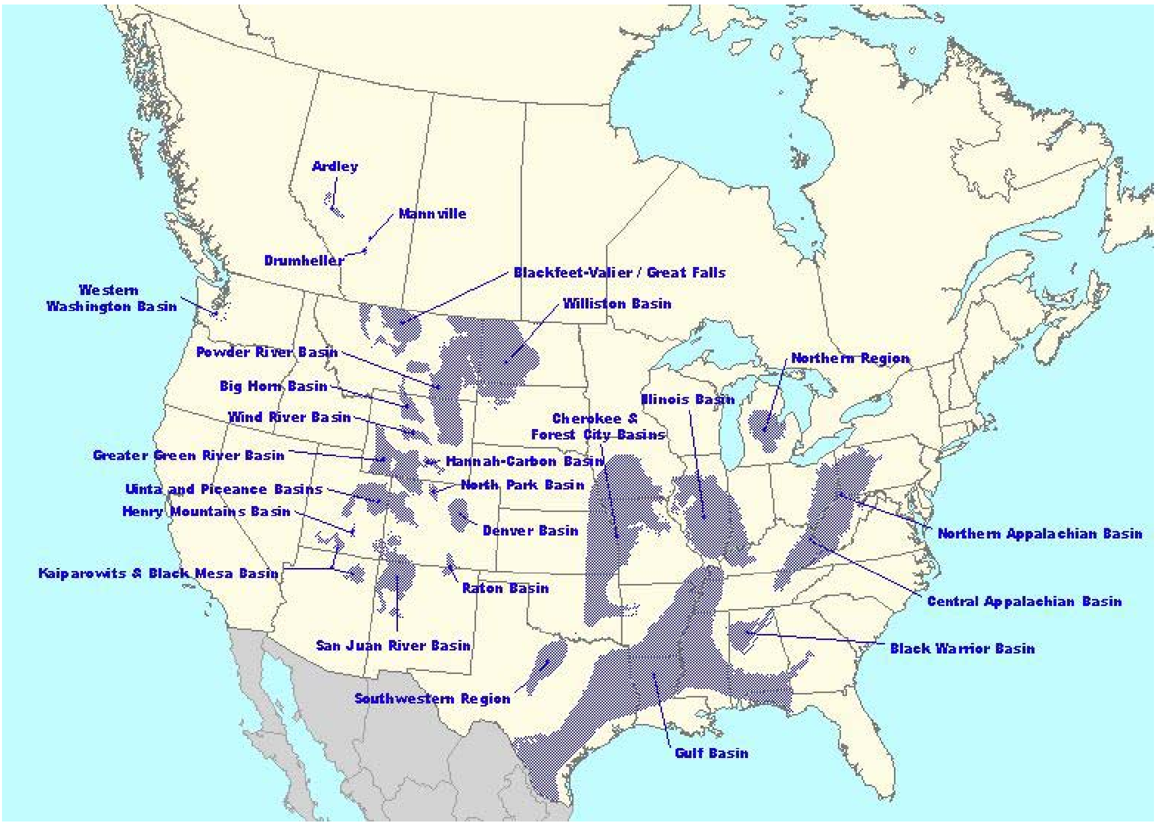

Figure B.4. North American Coal Basins with CO_2 Storage Potential

Table B.8. CO_2 Storage Capacity in U.S. Coal Basins

Coal Basin	Capacity ($MtCO_2$)
Big Horn Basin	490
Black Warrior Basin	900
Blackfeet-Valier / Great Falls	600
Central Appalachian Basin	100
Cherokee and Forest City Basin	900
Denver Basin	180
Greater Green River Basin	7,800
Gulf Basin	2,000
Hannah-Carbon Basin	3,000
Henry Mountains Basin	1,600
Illinois Basin	1,300
Kaiparowits and Black Mesa Basins	120
North Park Basin	910
Northern Appalachian Basin	3,400
Northern Region	60
Powder River Basin	13,600
Raton Basin	500
San Juan River Basin	10,400
Southwestern Region	3,500
Uinta and Piceance Basins	4,200
Western Washington Basin	2,300
Williston Basin	300
Wind River Basin	1,400
Total U.S. Coal Capacity	**59,560**

Table B.9. CO_2 Storage Capacity in Canadian Coal Seams

Coal Zone	Capacity ($MtCO_2$)
Ardley	**4,421**
Ardley Zone 1	*1,616*
Ardley Zone 2	*97*
Ardley Zone 3	*359*
Ardley Zone 4	*2,349*
Drumheller	**662**
Drumheller Zone 1	*116*
Drumheller Zone 2	*17*
Drumheller Zone 3	*525*
Drumheller Zone 4	*4*
Mannville	**306**
Mannville Zone 1	*6*
Mannville Zone 2	*10*
Mannville Zone 3	*290*
Total Canadian Coal Capacity	**5,389**