WMO **INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE** UNEP
Working Group III: Mitigation of Climate Change

WORKSHOP ON CARBON DIOXIDE CAPTURE AND STORAGE

PROCEEDINGS

Regina, Canada, 18-21 November 2002

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Preface

The Intergovernmental Panel on Climate Change (IPCC) was jointly established by the World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP) to assess available information on the science, impacts and the economics of climate change and of mitigation options to address it. It provides also, on request, scientific/technical/socio-economic advice to the Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC). Since its inception, the IPCC has produced a series of Assessment Reports, Special Reports, Technical Papers, methodologies and other products which have become standard works of reference, widely used by policymakers, scientists and other experts.

At the IPCC plenary meeting in Geneva, from April 17th to 20th 2002, a decision was taken regarding further work on Carbon Capture and Storage. The issue of carbon capture and storage has received little attention in the Third Assessment Report due to limited published scientific information. In the Plenary meeting, the Panel acknowledged the importance of issues related to capture and storage of CO_2 and decided that, to support a decision on the preparation of a Special Report, an IPCC Workshop should be organised.

Carbon capture and storage is increasingly seen as a possible option for mitigating climate change. The application of carbon capture and storage, however, is mostly still in the research or testing phase. In order to provide decision-makers with a good basis to consider application of this technology, more insight is needed in the issues surrounding the technology. Technical, economic, environmental and safety questions will have to be clarified.

The aim of the IPCC workshop is to produce a scoping paper on possible ways for IPCC to provide an assessment on carbon capture and storage. The most prominent option seems to be to produce a Special Report. The IPCC Plenary, where the decision regarding a possible Special Report will be taken, will take place in February 2003. The scoping paper will therefore outline a possible structure of such a report and provide an assessment of the availability of published scientific literature on the topic. Another product of the workshop will be the Workshop proceedings, published as supporting material of the IPCC and containing the revised, completed and updated versions of the papers presented during the workshop.

Before you lays the collection of the papers that are presented at the IPCC workshop on carbon capture and storage. The 13 lectures serve as a background for the drafting of the scoping paper.

We extend our sincere gratitude to the Canadian government for hosting this workshop. The organisation was well led by Dr. Malcolm Wilson of the University of Regina Also the organisation of the excursion to the Weyburn site is very much acknowledged. We also thank the members of the Programme Committee, who gave invaluable advice on programme, participants and papers.

We would like to encourage all participants to contribute to a constructive and fruitful meeting, where exchanging views and opinions on the issues surrounding carbon capture and storage will lead to more clarity of the issues involved and the current status of scientific research. We hope that this workshop will be the first step in an increased understanding of the applicability of carbon capture and storage for mitigation of climate change.

Ogunlade Davidson
Bert Metz
Co-chairs of Working Group III

Foreword from Canada to the IPCC WG III Workshop on Carbon Capture and Storage

November 18-21, 2002, Regina, Canada.

Dear Delegates,

In response to the request from the Seventh Session of the Conference of Parties (COP-7) to the United Nations Framework Convention on Climate Change and the decision adopted by IPCC at its plenary meeting in Geneva in April, 2002, Canada is pleased and delighted with the acceptance of our offer to host the first IPCC workshop on Carbon Capture & Storage. On behalf of the Government of Canada and as the Canadian Delegate and Chair of the IEA Greenhouse Gas R&D Programme, it gives me great pleasure to welcome you to Regina and Canada.

Canada's involvement in several aspects of Carbon Capture and Storage technologies are deep rooted, with work underway on research and development and industrial projects since the late 1980's. In 1991, Canada was among 12 countries in the International Energy Agency (IEA) who were the founding members of the IEA Greenhouse Gas R&D Programme. Since that time, the IEA Greenhouse Gas R&D Programme has been the focus of international initiatives and collaboration underway for the assessment of options to promote deep reductions in anthropogenic GHG emissions through Carbon Capture and Storage. In the intervening period since 1997, new initiatives promoted under a National Implementation Strategy on Climate Change adopted by Canadian federal, provincial and territorial ministers of energy and the environment, have resulted in significantly more activity on CO_2 Capture and Storage projects within our borders. We hope to give you a flavour of our national initiatives in a special *'Canada Day'* event that we have put together for November 18th, on the day preceding commencement of the formal IPCC workshop.

Several Canadian organizations and the IEA Greenhouse Gas R&D Programme have contributed their support to organising this event. Special thanks are due to Dr. Malcolm Wilson and the University of Regina as the local organizer, and ENCANA for the field trip to the Weyburn project. Thanks too to the Government of Canada's Climate Change Action Plan, Natural Resources Canada (through the Environmental Policy Division, Office of Energy Research and Development and CANMET Energy Technology Centre) and the Governments of Saskatchewan and Alberta for their financial support. I also wish to acknowledge the special interest and leadership of Dr. Raj Pachauri, Chair of the IPCC, Bert Metz and Ogunlade Davidson, Co-Chairs of IPCC WG III, and my colleagues in the WG III programme and organising committees. A special mention is also in order for the invited speakers whose contributions in the attached proceedings will be the basis for our dialogue at the workshop.

Last but not least, a big thank you to you the delegates for your attendance and the most important part to come from your contributions at this event. Undoubtedly, we are positioned to set a seminal stage in the approach and collective will of humanity to prevent the dangerous rise in GHG concentrations in the Earth's atmosphere that is the cause of global warming and climatic change.

With my best wishes for a successful outcome to our meeting, bon voyage and welcome to Canada!

Kelly Thambimuthu

Dr. Kelly Thambimuthu,
Senior Scientist, CANMET Energy Technology Centre, Natural Resources Canada Chairman,
IEA Greenhouse Gas R&D Programme

Canada

Terms of Reference

At the IPCC plenary meeting in Geneva, from April 17th to 20th 2002, a decision was taken regarding further work on Carbon Capture and Storage (see proposal in IPCC-XIX/Doc. 9 and draft report of meeting). The issue of CO_2 capture and storage has received attention in the TAR, but due to limited published scientific information only a few pages were devoted to technological progress, costs and the environmental risks that arise when this kind of technology is applied. In the Plenary meeting, the Panel acknowledged the importance of issues related to capture and storage of CO_2 and decided that, to support a possible decision on the preparation of a Special Report, an IPCC Workshop should be organised under the auspices of Working Group III, with inputs from WG I and II.

Objectives and scope of an IPCC Workshop on Carbon Capture and Storage
The Workshop should result in a scoping paper for further IPCC work on this issue. The most promising option for further work seems to be a Special Report, but the option of assessing the information on this issue as part of the FAR is also to be considered. Preliminary contents of a possible Special Report on Carbon Capture and Storage should include (according to Decision 7 in the IPCC Plenary in April):

- Sources of CO_2 and technologies for CO_2 capturing
- Transport of CO_2 from capture to storage
- Geographical potential of the technology (minimise distance between source and storage locations)
- Re-use of captured CO_2 in industrial applications
- CO_2 storage options, including:
    - Deep saline water-bearing formations (saline aquifers)
    - Depleted oil and gas reservoirs
    - Oil reservoirs that may be used for CO_2 Enhanced Oil Recovery (EOR)
    - Deep coal seems containing methane (Enhanced Coal Bed Methane Recovery, ECBM)
    - Deep ocean storage
- Costs and energy efficiency of CO_2 capturing and storing in comparison with the costs of other large-scale options, especially in the area of electricity generation and use
- Implications of large-scale introduction; long-term technological and economic implications of carbon storage technologies (e.g. hydrogen)
- Environmental impacts
- Risks and risk management during capture, transport and storage
- Monitoring of CO_2 storage
- Impediments and barriers to the implementation of geological carbon storage
- Modelling of CO_2 storage in energy and climate models
- Implications for national and international emission inventories
- Legal aspects

The Workshop will assess the state of knowledge and the prospects of ongoing research of these issues to deliver sufficient scientific and technical information for a Special Report. Since in October 2002 in Kyoto already a conference[1] focussing on the technical side of CO_2 capture and storage will be held, the presentations during the Workshop should only summarise the current situation and focus on the question when certain new information will be available for a Special Report or a FAR activity.

Workshop participants and task
The Workshop should be attended by 50 to 60 experts from different regions, covering all areas of research indicated above and originating from universities, governments, non-governmental organisations and the private sector. About 5 to 6 people should be available per subject to elaborate the various issues in subgroups.

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[1] The 6th International Conference on GHG Control Technologies, 1-4 October, Kyoto, Japan.

Governments will be asked to nominate scientists both as participants and as authors for a Special Report. A Programme Committee will be responsible for developing the workshop programme and will advise on the selection of the participants of the Workshop as well as of the Special Report.

Date, venue and programme outline

The Workshop will begin on November 18 with a field trip, kindly organised by the host government of Canada. The IPCC programme will start on November 19 and end on November 21. The venue is Regina, Canada. A plenary meeting of about one and half a day will give a brief overview of the state-of-the-art and future developments regarding all topics listed above, where after specialist subgroups will draft specific contributions to a scoping paper in parallel meetings. A plenary meeting at the end will discuss the findings and recommendations of the subgroups. During the last day, a selected drafting group will derive a scoping paper as requested, which will be submitted to the IPCC Plenary during the first quarter of 2003. The meetings of the drafting group may be extended to November 22, if required. Papers on the presentations and the reports by the subgroups will be published in the workshop proceedings.

Call for nominations

No.12436-02/M/IPCC/SR *Geneva, 17 June 2002*

Sir/Madam,

I have the honour of bringing to your attention an IPCC Workshop on Carbon Capture and Storage, scheduled to be held from 19 to 21 November 2002, in Regina, Canada.

It may be recalled that the IPCC has been established jointly by the World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP) to:

a. assess all available factual information on the science, the impacts and the economics of climate change and on the adaptation/mitigation options to address climate change,
b. assess, and if necessary develop, methodologies such as the IPCC Guidelines for National Greenhouse Gas Inventories and
c. provide, on request, scientific/technical/socio-economic advice to the Conference of the Parties to the United Nations Framework Convention on Climate Change and its bodies.

At the IPCC plenary meeting in Geneva, from April 17th to 20th 2002, a decision was taken regarding further work on Carbon Capture and Storage. The issue of carbon capture and storage has received little attention in the Third Assessment Report due to limited published scientific information. In the Plenary meeting, the Panel acknowledged the importance of issues related to capture and storage of CO_2 and decided that, to support a decision on the preparation of a Special Report, an IPCC Workshop should be organised under the auspices of Working Group III with inputs from WGI and II.

The Workshop should result in a scoping paper for further IPCC work on this issue. The most promising option for further work seems to be a Special Report, but the option of assessing the information on this issue to be a part of the Fourth Assessment Report (FAR) is also to be considered. Preliminary contents of a possible Special Report on Carbon Capture and Storage should include (according to Decision 7 in the IPCC Plenary in April):

- Sources of CO_2 and technologies for CO_2 capturing
- Transport of CO_2 from capture to storage
- Geographical potential of the technology (minimise distance between source and storage locations)
- Re-use of captured CO_2 in industrial applications
- CO_2 storage options, including:
    - Deep saline water-bearing formations (saline aquifers)
    - Depleted oil and gas reservoirs
    - Oil reservoirs that may be used for CO_2 Enhanced Oil Recovery (EOR)
    - Deep coal seems containing methane (Enhanced Coal Bed Methane Recovery, ECBM)
    - Deep ocean storage
- Costs and energy efficiency of CO_2 capturing and storing in comparison with the costs of other large-scale options, especially in the area of electricity generation and use
- Implications of large-scale introduction; long-term technological and economic implications of carbon storage technologies (e.g. hydrogen)
- Environmental impacts
- Risks and risk management during capture, transport and storage
- Monitoring of CO_2 storage
- Impediments and barriers to the implementation of geological carbon storage
- Modelling of CO_2 storage in energy and climate models
- Implications for national and international emission inventories
- Legal aspects

It is with great pleasure that I extend this invitation to your Government to nominate experts for participation in the Workshop. Given its specialised, scientific-technical nature, attendance by appropriate experts is vital for the success of the Workshop. Thus, it would be most helpful if your Government nominates its representative(s) with appropriate expertise and technical background in the fields mentioned above. This will also facilitate fruitful discussions within the smaller, parallel task groups that are planned, which will form a substantial part of the Workshop programme.

The attendance at the Workshop is limited to a total of 60 participants. Nominees invited to attend will receive further information on the Workshop.

In April, the IPCC Plenary also decided to start the process of nominations for Lead Authors for a possible Special Report on the same issue, that may be undertaken if the IPCC 2003 Plenary so decides. I therefore also extend an invitation to your Government to nominate experts for such a task. The fields of expertise required are the same as identified for the Workshop. Please keep in mind that Lead Authors should be capable of investing appropriate time in the writing of the Report over a period of at least one year, starting in the first quarter of 2003. Nominating experts both for the Workshop and as authors for a possible Special Report is recommended.

I request that the nomination(s) be made by completing the appropriate forms in the attachments (one per nominee per activity) and forwarding it/them to Heleen de Coninck, IPCC Working Group III Technical Support Unit at fax +31 20 4922812 or e-mail (deconinck@ecn.nl) no later than 30 August 2002.

Limited financial support is available from the IPCC Trust Fund to representatives from the developing countries and countries with economies in transition, one per country. Part of the available funds may be reserved for the experts to be invited by the IPCC. The offer of support to the government nominees will take into account the following factors, in the order mentioned: (i) balance of expertise across the various disciplines represented at the Workshop, (ii) balanced geographical representation and (iii) chronology of requests received. Nominations for financial support should also reach Ms. de Coninck no later than 30 August 2002. This deadline will be strictly adhered to because of the time required for the logistics of delivering the support.

Copies of this letter are being sent to the IPCC Focal Point (or Permanent Representative for IPCC if you have such designation) and Contact Point(s), if any, the Permanent Representative with WMO and Focal Point(s) of UNEP of your country for information.

Accept, Sir/Madam, the assurances of my highest consideration.

G. Love
Secretary of the IPCC

SCOPING PAPER
IPCC SPECIAL REPORT ON
CARBON DIOXIDE CAPTURE AND STORAGE

Introduction

At the 19th IPCC plenary meeting in Geneva, April 2002, it was decided[2] to hold a workshop in the fourth quarter of 2002 to consider the issues associated with geological and oceanic carbon separation, capture and storage. The outcome of the workshop should be an expert advice to the Panel whether to develop a Special Report on this topic or to incorporate the issue in the Fourth Assessment Report. In case the experts would recommend a Special Report, the workshop should deliver a scoping paper, timetable and detailed outline for a Special Report and a proposed list of authors for decision by the Panel at its next Session (18-21 February 2003). This scoping paper is the result of the workshop.

Workshop on Carbon Capture and Storage

From 18-21 November 2002, the IPCC workshop on carbon capture and storage was held in Regina, Canada under the auspices of Working Group III. About 200 experts indicated their interest in participation, but the maximum was set at 70 participants. The participants originated from 24 different countries. Thirteen presentations were given and discussions were held covering the area of sources, capture, transport, geological storage and ocean storage. The presentations addressed a wide range of issues including long term energy system implications, technical, environmental, safety, economic and legal aspects, and consequences for emission inventories[3]. Eight breakout groups prepared the input to a Drafting group that agreed on a structure and contents of an IPCC Special Report (see section 4.2).

During the workshop, a field trip was organised to visit the Weyburn Monitoring Project. In this project, CO_2 transported from a Coal Gasification facility in Beulah, North Dakota, USA, is injected in oil wells, resulting in enhanced oil recovery. The oil revenue forms the basis for commercial viability and the CO_2 used in the project will remain stored in the reservoirs.

Why a Special Report?

The mandate of the Workshop was to support a decision by the IPCC Plenary meeting on a Special Report on Carbon dioxide Capture and Storage by 2005 or inclusion of this subject in the Fourth Assessment Report (AR4) by 2007. The participants discussed this issue and concluded that a Special Report would be the appropriate choice for the following reasons:

- Carbon dioxide capture and storage is an emerging technological option with a very high mitigation potential. It has been suggested that about half the world cumulative emission to 2050 may be stored at costs comparable to other mitigation options.
- The keen interest in this subject is demonstrated by plans considered by several leading industrial countries to invest in this emerging technology in the coming years.
- In the Marrakech Accords (2001), UNFCCC expressed its interest in the subject by inviting IPCC to prepare a Technical Paper on geological carbon storage technologies, covering current information, and report on it for the consideration of the 2nd COP/MOP[4]. However, a Technical Paper would be repetitious with the very limited material covered in the IPCC TAR of WG III. Conversely, a Special Report would recognise the range of new literature that could provide a basis for a comprehensive and up-to-date IPCC assessment.

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[2] See www.ipcc.ch , Draft Report of the Nineteenth Session of IPCC, Geneva 17-20 April 2002, Appendix C decision 7, p.45-46

[3] The proceedings of this meeting are expected to be published on the web by February 2003.

[4] See http://unfccc.int, Report of COP 7, document FCCC/CP/2001/13/Add.1, Decision 9/CP.7 (Art. 3.14 of the Kyoto Protocol), Draft decision -/CMP.1, para 7, page 50: '*Invites* the Intergovernmental Panel on Climate Change, in cooperation with other relevant organisations, to prepare a technical paper on geological carbon storage technologies, covering current information, and report on it for the consideration of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol at its second session'.

- There is a growing interest in the scientific and technical community in the subject of carbon dioxide capture and storage, demonstrated by the growing availability of literature.
- Policymakers have a growing need for a reliable synthesis of the available scientific literature in order to facilitate the decision making process on the plans for carbon dioxide capture and storage as a climate change mitigation option.
- A first survey of available scientific and technical literature indicates that there generally is sufficient to ample material (including the output of the IEA Greenhouse Gas R&D Program) to cover the relevant areas for an Assessment Report.
- Inclusion of this subject as a chapter in the AR4 would necessarily mean that only a limited assessment of the new literature would be possible. In that case, IPCC could not ensure the provision of a complete and balanced picture of carbon dioxide capture and storage. Conversely, a Special Report would be able to cover all relevant issues.
- Preparation of a Special Report on carbon dioxide capture and storage would not interfere with preparation of AR4 and other activities given the specific nature of the topic and its timing.

Proposed Content of a Special report

4.1 Title
The 19th session of IPCC gave a mandate to hold a workshop on ***carbon** capture and storage*. As a matter of fact, it is not ‘carbon’ but ‘carbon dioxide’ that is stored. Therefore, it is proposed to the IPCC 20th session to decide to change the title into ‘***carbon dioxide** capture and storage’*

4.2 Contents
The following structure was felt to ensure the best possible treatment of the Carbon Dioxide Capture and Storage issues:

1. Introduction (CO_2 emissions and projections; stabilisation options of GHG concentrations; possible role of carbon dioxide capture and storage for deep CO_2 emission reductions; CO_2 storage in relation to other mitigation options; general explanation and guidance with system diagrams; the importance of carbon dioxide retention time-scales)

2. Sources (characterisation of emission sources; geographical distribution of emission sources; matching of sources and sinks; climate neutral energy carriers and system transitions and the implications for CO_2 sources from direct fuel use)

3. Capture (capture systems; technological options for separation; system integration; optimisation of capture; advances in capture systems and enabling technologies; hydrogen; distributed applications; monitoring, risk, and legal aspects for capture systems; capture costs)

4. Transport (Pipelines (regional, national); ships; monitoring, risk and legal aspects for transport systems; transport costs)

5. Geological storage
    - 5.1. Introduction
    - 5.2. Storage formations and capacity (depleted gas fields, oil fields, unminable coal seams, and saline aquifers)
    - 5.3. Site selection and performance assessment
    - 5.4. Injection technology and well field operations
    - 5.5. Monitoring technologies
    - 5.6. Verification
    - 5.7. Environmental impacts and risks (e.g. leakage)
    - 5.8. Legal issues and public acceptance
    - 5.9. Costs

6. Ocean storage
    6.1. Introduction
    6.2. Storage formations and capacity (mid-ocean injection, sea floor options, and carbonate neutralisation)
    6.3. Site selection and performance assessment
    6.4. Injection technology and well field operations
    6.5. Monitoring technologies
    6.6. Verification
    6.7. Environmental impacts and risks (e.g. leakage)
    6.8. Legal issues and public acceptance
    6.9. Costs

7. Re-use and other storage options (re-use technologies and other storage technologies such as mineralisation; potential in terms of avoided CO_2 emissions; energy use, life cycle analysis and practical feasibility)

8. Total costs and market potential (model approaches and assumptions; building up the full cost chain; potential for cost reduction; economic potential and implications)

9. Implications for emission inventories and accounting (greenhouse gas emission inventories; accounting issues)

10. Critical Gaps in knowledge

Time schedule and provisional budget estimate

If the Plenary decides to approve of a Special Report, delivery would be planned in the first half of 2005. In contrary to the request by the COP-7, the report will not be ready by the 2nd COP/MOP, which presumably will take place at the end of 2004. 2 Lead Author meetings in 2003 and 2 Lead Author meetings in 2004 are foreseen. The planning would be made to properly synchronise with the preparation of the AR4 and a possible Special Report on Fluorinated gases.

Budget 2003: assuming 2 Lead Author meetings, assuming 20 journeys of DC and EIT lead authors per meeting at 5.740 CHF per journey, and assuming that local meeting costs will be met by in-kind contributions, *229.600 CHF* will be needed from the IPCC Trust fund.

Budget 2004; 2 * 20 journeys of DC and EIT Lead Authors = approx. 229.600 CHF. In addition, 4 review editors from DC and EIT will be invited at the LA-meetings, which corresponds to another 45.920 CHF. The total budget for 2004 will them amount up to *275.520 CHF.*

Budget 2005: Plenary WG III meeting (likely combined with approval of Special Report on Fluorinated Gases); assuming 3 days for the Summary for Policy Makers on this subject will cost approx. 845.000 CHF. Costs for translation and purchasing of the Special Report, shipping costs and outreach are to be included later.

6. Lead author selection process

Nominations were called for in a letter to governments, dated June 17, 2002. Based on the nominations, the IPCC Bureau (Paris, February 2003) will select the Co-ordinating Lead Authors, Lead Authors, and Review Editors (see separate document **[to be prepared]**).

CONTENTS

Overview of CO_2 emission sources, potential, transport and geographical distribution of storage possibilities

John Gale
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Abstract

Capture and storage of CO_2 has the potential, when used in combination with other mitigation options, to make deep reductions in greenhouse gas emissions. Geological storage is the preferred storage option because the reservoirs potentially have sufficient storage capacity to hold the required volumes of CO_2. Any capture and storage project involves three distinct phases; capture of the CO_2 from the emission source, dehydration followed by compression and transportation of CO_2 and finally injection of CO_2 into reservoirs at the storage site. To develop an understanding of the real potential of CO_2 capture and storage for reducing CO_2 emissions worldwide it is necessary to gain an awareness of the geographical distribution of the CO_2 emissions and the storage reservoirs. Once the geographical relationship between sources and storage reservoirs is clear then transportation networks for the CO_2 can be considered. This paper will review research activities underway worldwide that are developing the understanding of the geographical relationship between emission and storage site mapping, appraise the status of the work and indicate where additional work is needed to close any gaps in our understanding.

Introduction

If deep reductions in greenhouse gas emissions are required, to meet the UNFCC goal of stabilisation of anthropogenic greenhouse gas emissions, then one method that could be used is CO_2 capture and storage. CO_2 capture and storage technology would be used in combination with the other mitigation measures, such as fuel switching, energy efficiency and renewable energy to achieve the necessary deep reductions in greenhouse gas emissions [1].

CO_2 can be captured from a variety of anthropogenic sources such as power plants and large industrial plants and then compressed and transported to a storage site. There are two potential storage options, which are; storage in the oceans or in geological reservoirs [2]. Currently, there are considerable uncertainties about the science of ocean storage. In addition, there are attendant legal issues that need to be addressed. Hence, ocean storage is less likely to be promoted as a mitigation option in the current situation. Geological storage of CO_2 is a more promising storage option capable of achieving deep reductions in the foreseeable future. There are a number of potential geological trap types that can be used to store captured CO_2. These include; depleted and disused oil and gas fields, deep saline aquifers and deep unminable coal seams [2]. Some examples of the geological traps under consideration have already held hydrocarbons or liquids for many millions of years.

The paper attempts to answer the question; how much of the emitted CO_2 can be effectively stored within geological reservoirs? In attempting to answer this question, the paper sets out to examine the relationship between emissions of CO_2 and the geological storage reservoirs that could be used to store the CO_2. To do this, it is necessary to gain an awareness of the geographical distribution of the sources of CO_2 emissions and compare that with the geographical distribution of the geological storage reservoirs. Once the geographical relationship between sources and storage reservoirs is clear, then transportation networks for the CO_2 can be considered. Obviously there are costs associated with each component of the process, but if many long distance (>1000 km) pipelines are necessary to link sources and reservoirs this will have potential economic consequences unless large trunk pipelines can be developed with high flow rates to reduce the unit costs.

CO_2 emission sources

The IEA Greenhouse Gas R&D Programme (IEA GHG) has compiled a database of the major anthropogenic stationary sources of CO_2 [3]. In the context of this paper, stationary emission sources are considered to be power plants and large industrial manufacturing plants. The database contains some 14 641 entries and has collated data on current CO_2 emissions from: power plants, oil refineries, gas processing plants, major industrial sources (ammonia, cement, and iron and steel plants), hydrogen plants, ethylene and ethylene oxide plants.

The data contained within the database was compiled from a variety of publicly available and referencable sources. The database contains information by plant name, company name, location (city, country, and region) latitude and longitude co-ordinates, annual CO_2 emissions (for base year) and CO_2 emission concentrations. The latitude/longitude co-ordinates allow the data to be used in any Geographical Information System (GIS), which will allow matching of emission sources with storage reservoirs to be undertaken. The addition of the geographical co-ordinates to the database was achieved by retrieving the co-ordinates from the United States Geographical Survey's Geological Names Information System (GNIS).

The cumulative world CO_2 emissions from the 14 641 entries in the database was 13.44 Gt/y in 2000. The total CO_2 emissions from the power generation and industrial sectors in the database were compared with those in the International Energy Agencies World Energy Outlook [4] and good agreement was observed, which gives confidence in the magnitude of the total emissions within the database. To put these stationary source emissions in context, global emissions of CO_2, from all anthropogenic emission sources quoted in World Energy Outlook were 22.6 Gt/y in 1997 [4]. The total emissions from power production and all industry sectors quoted in World Energy Outlook was 14.2 Gt/y or 63% of global anthropogenic CO_2 emissions. The difference between the power and industry source emission data in the IEA GHG study and those from the World Energy Outlook can be explained because not all industry sectors which emit CO_2 were considered in the IEA GHG study. For example, industry sectors such as glass manufacture were excluded from the IEA GHG study because such industries do not tend to produce large point source emissions of CO_2. In contrast, anthropogenic CO_2 emissions from the transport sector equate to 4.8 Gt/y or 21% of global anthropogenic CO_2 emissions.

Based on World Energy Council growth projections, CO_2 emissions from all sources were estimated to grow by 36% in 2010 (to 18.24 Gt/y) and by 76% in 2020 to 23.31 Gt/y compared to the 2000 base level.

The distribution of stationary CO_2 emission sources on a regional basis is shown in Figure 1. North America is the region with the largest number of stationary CO_2 sources (37%) followed by OECD Europe (14%) and China (10%). Figure 1 indicates three large clusters of stationary CO_2 emission sources, in the mid and eastern states of the USA, in central regions of Europe (UK, Netherlands, Germany, Austria, Hungary, Czech Republic) and in South East Asia (eastern China and Japan) with a further smaller cluster around the Indian sub continent.

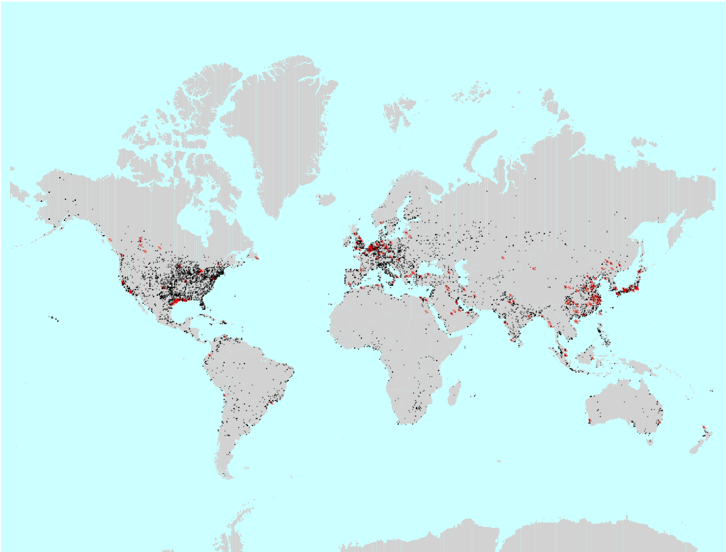


Figure 1 Worldwide Distributions of CO_2 Emission Sources

The quantities of stationary CO_2 emissions for each region are shown in Figure 2 as a proportion of the total 2000 stationary emissions. This distribution indicates that the regions that are the largest emitters of CO_2 from stationary sources are: China, 25% (3.4 Gt/y), North America, 20% (2.69 Gt/y) and OECD Europe, 13% (1.75 Gt/y). All other regions emit less than 10% of the total CO_2 emission from stationary sources in 2000.

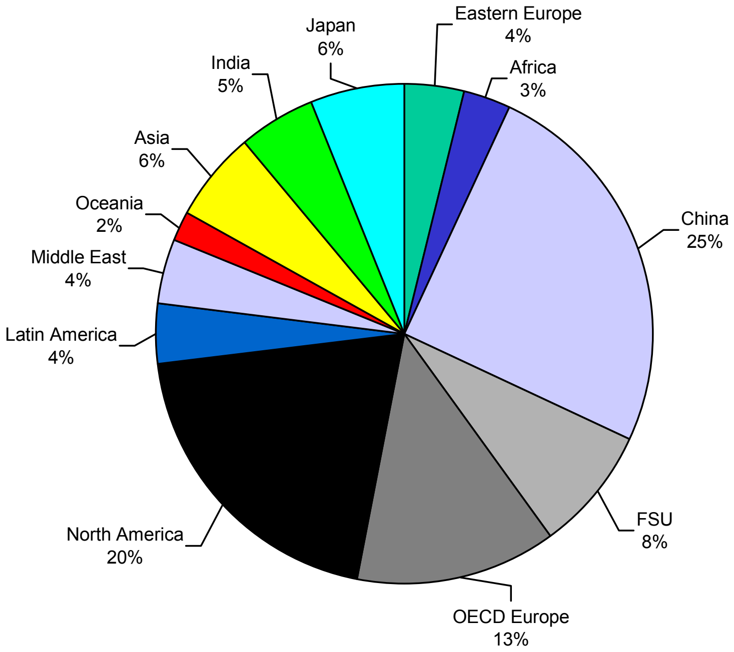


Figure 2 CO_2 Emission Sources by Geographical Region

The distribution of stationary CO_2 emission sources by industry sector is shown in Figure 3. Power plants dominate the statistics with 54% of all identified stationary CO_2 emission sources. The next highest category is the cement industry with 15% of all sources and the gas processing sector, 12% of all sources.

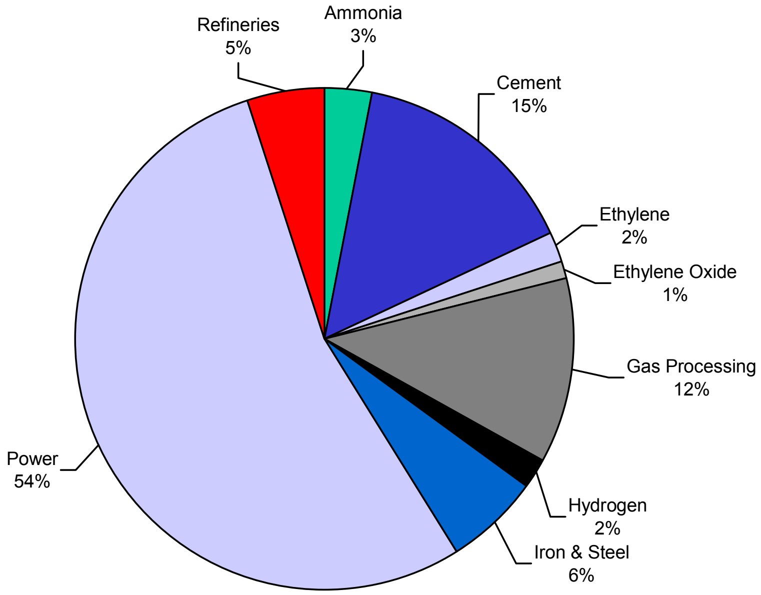


Figure 3 Distributions of CO_2 Emission Sources by Industry Sector

Mapping of CO_2 emission sources is underway in a number of countries world-wide; these activities are discussed in Section 3.

Geological storage potential and geographical distribution of storage possibilities

Geological Storage Potential

The global storage capacity for the main geological storage reservoirs has been estimated by IEA GHG and is compared with the projected total amount of CO_2 that needs to be stored between 2000 and 2050 according to IPCC's 'business as usual' scenario in Table 1 [2]. The storage capacities quoted are based on injection costs of up to 20 US $ per tonne of CO_2 stored.

Table 1 Estimate of Storage Capacities for Different Geological Trap Types

Storage Option	Global Capacity	
	[Gt CO_2]	[%] of total emissions to 2050
Depleted gas fields	690	34
Depleted oil fields/CO_2 EOR	120	6
Deep saline aquifers	400 - 10 000	20 - 500
Unminable coal seams	40	2

The capacity estimates for these reservoirs show that geological storage of CO_2 can make a substantial impact on CO_2 emissions reduction. From a capacity perspective, deep saline aquifers offer a very significant potential. However, as can be seen in Table 1 there is considerable uncertainty in the estimates for CO_2 storage capacity in aquifers. These estimates were made in the early 1990's, but need to be firmed up by additional research [5]. Depleted oil and gas fields also have a significant storage potential, capable of accepting 40% of the CO_2 that needs to be stored. It must be noted that the storage potentials for oil and gas fields exclude fields that are not yet producing. Conversely, from a global perspective, storage of CO_2 in deep unminable coals seams will not have a significant impact; however, there may well be some regional niche opportunities where its potential could be more significant. Overall, geological reservoirs have sufficient potential storage capacity to make significant reductions in global CO_2 emissions.

However, these global storage potentials in geological reservoirs must be considered as the 'theoretical' potential. These potentials were developed by the IEA Greenhouse Gas R&D Programme using general assumptions about the amount of CO_2 that can be stored in the respective reservoirs. These potentials were determined to allow global estimates of the costs of CO_2 storage to be determined.

The storage capacities that can be achieved in practice will potentially differ from the theoretical potentials. To determine the actual or 'realisable' potentials more in depth analysis of the storage reservoirs is needed. Research is underway that should provide the more detailed analyses of the reservoirs in a number of countries/regions of the world. The countries/regions involved include:

• Australia	Aquifers, oil and gas fields and coal seams
• Canada	Aquifers, oil and gas fields and coal seams
• Japan	Aquifers and coal seams
• North West Europe	Aquifers, oil and gas fields and coal seams
• USA	Aquifers, oil and gas fields and coal seams

The research activities cover some of the main regions of the world where there are clusters of CO_2 emission sources, i.e. USA and Europe as highlighted earlier in Section 2. However, regions such as South East Asia are not being researched extensively, only Japan is undertaking work in that region and the Indian sub-continent is not being researched at all to the author's knowledge.

Geographical Distribution of Potential Storage Sites

As mentioned earlier a number of research groups are investigating the geographical distribution of storage sites within their regions. The activities of the research projects are summarised below:

Australia - The GEODISC project had undertaken a detailed assessment of the potential geological storage sites in Australia [6, 7]. For Australia, it has been concluded that opportunities for CO_2 EOR and CO_2 storage in deep unminable coal seams are limited and only niche opportunities may occur. Also, due to the immaturity of oil and gas production in Australia, storage of CO_2 in depleted gas fields is not a near term opportunity. The largest fields are only likely to become depleted in the next 30-40 years. CO_2 storage in deep saline aquifers is, therefore, likely to be the most likely route for storing large volumes of CO_2 in Australia.

The GEODISC project has undertaken a screening process to identify all sedimentary basins in Australia where CO_2 storage might be viable. The screening process included an assessment of all sedimentary basins that from a geographical viewpoint were adjacent to known major emissions sources, or which might in the future require potential injection sites to store CO_2 emissions. Approximately 300 known sedimentary basins were screened and reduced down to 48 basins based on a technical assessment of each basin. From these 48 basins 65 potential storage sites were identified, for which the CO_2 storage capacity was determined at 740 Gt of CO_2. This estimate often relies on only the best site in an individual basin, not the total capacity of each basin, and each capacity has been heavily discounted by assuming a technical risk factor for each site. The total 'theoretical' capacity for Australia would be at least an order of magnitude higher [6, 7].

Canada - Study work by the Alberta Geological Survey has indicated that the only sedimentary basins in Canada with significant potential for the geological storage of CO_2 are the Alberta Basin and the Canadian part of the Williston Basin, otherwise known together as the Western Canada Sedimentary Basin [8]. Currently a study by the Alberta Geological Survey is underway to estimate the storage potential in the Western Canadian Basin. The results of this work will be available in early 2003 [9]. Preliminarily estimates range from tens to hundreds of Gt CO_2. Some small sedimentary basins, with very low potential for CO_2 geological storage, are present in south-western Ontario and along the St. Lawrence River in Quebec.

The Western Canada Sedimentary Basin is also rich in oil, gas, heavy oil, oil sands and coal, and is a major North American energy producer. The Alberta Geological Survey is also currently assessing the potential for CO_2 storage in oil and gas reservoirs in Alberta [9]. There are currently some 26 000 gas pools and 8 500 oil pools in various stages of production and depletion. The Alberta Utilities and Energy Board have estimated the CO_2 storage potential in gas fields as 9.8Gt of CO_2. In depleted oil fields the storage capacity has been estimated as 637 Mt of CO_2 and storage in CO_2 EOR operations could be as high as 673 Mt. Work is currently underway to firm up the storage potential estimates; this work will be complete in the first quarter of 2003.

Estimation of the CO_2 storage potential in deep unminable coals seams is being undertaken by the Canadian Geological Survey (CGS) [9]. Again this work should be complete in 2003. Separate from the CGS work a study is looking in detail at CO_2 storage in deep unminable coal seams in Nova Scotia, which has relatively small coal producing sedimentary basins, where power generation is coal-based. Geological sequestration of CO_2 in coal seams could be an option in the future in Nova Scotia once these coals are deemed as unminable and the technology is proven.

Europe - An initial assessment of the geological storage potential in Europe was undertaken by a team of geologists and scientists led by the British Geological Survey in the early 1990's [10]. The project undertook an assessment of the emissions of CO_2 from power plants in the European Union (EU) and Norway and made a preliminary assessment of the geological storage potential within the EU and Norway. It was estimated that the CO_2 storage capacity within the EU and Norway was 800 Gt CO_2. With emissions from power plants being 950 million tonnes per year in 1990, this equated to approximately 800 years of storage potential. The vast majority of the storage capacity (60%) was located in the North Sea on the UK and Norwegian continental shelf. The storage capacity estimates were considered to be provisional and further more detailed analysis on a case by case basis was recommended.

A new project commenced in 2000 called ‘European Potential for Geological Storage of Carbon Dioxide from Fossil Fuel Combustion’ or GESTCO for short [11]. GESTCO aims to build upon the work undertaken in the earlier EC supported study. The GESTCO project, however, does not focus on the whole of Europe, but merely on North West Europe (Belgium, Denmark, France, Germany, UK, Netherlands, and Norway) and Greece. The project is looking at the storage capacities in reservoirs in more detail by focusing on 12 case studies that reflect the range of storage reservoirs of interest. Each case study will involve a reservoir simulation exercise [12]. The project will end in 2003 and to date a compilation of the data on the storage capacities throughout the region has not been presented, but data on the potential storage capacities within a number of countries in North West Europe has been presented.

Japan - Estimates for the geological storage potential were undertaken in the early 1990’s by The Engineering Advancement Association of Japan (ENAA). These estimates indicated the potential to store some 92 Gt CO_2 in geological reservoirs, the majority of which (52 Gt) could be stored in aquifers offshore [13]. With emissions of CO_2 of 500 Mt/y from stationary sources it was deemed that there was a significant potential for geological storage in Japan. Some initial modelling work has been carried out in Japan to match CO_2 emissions sources with aquifer traps. This work has indicated some 1.4 Gt CO_2 could be cost effectively stored in offshore aquifers between 2000 and 2050, which equates to a ‘realisable’ storage potential in Japan [14]. The modelling work is continuing. .

A new research project began in 2001 in Japan that involves the Research Institute of Innovative Technology for the Earth (RITE) and ENAA, which will build upon the earlier research work [15]. The 5 year project will involve a number of activities which include:

- A field scale injection study to demonstrate the potential for CO_2 injection in Japan and gain data on the actual behaviour of carbon dioxide underground.
- A geological survey around the Pacific offshore region of Japan. The study will compile existing seismic and exploration data in the region and generate a GIS data base that will act as a support tool for future storage activities.
- Undertake a system analysis to assess possible combinations among locations of large-scale CO_2 sources and storage options. A cost evaluation model will be used to assess cost effective storage options for Japan.

The results from this latest project in Japan should start to become available from 2003 onwards and should provide information on the ‘realisable ‘potential for CO_2 on the Pacific coast of Japan.

USA - Assessments of the geological storage capacity and distribution of storage sites is underway in the USA, but the research is more fragmented than in other areas. Various research groups are looking at storage prospects in states and regions of the USA. These activities include:

- The GEOSEQ project has mapped and estimated storage potentials in aquifers and oil and gas fields in California. Aquifers offer the biggest potential; estimates of their capacity exceed 22 Gt CO_2 . Oil fields are next with the potential to store up to 2.5Gt CO_2 and finally gas fields at 0.6 Gt CO_2 [16].
- Battelle have studied in depth the Mt Simon sandstone formation that covers much of the Midwestern United States. The region consists of three deep basins, the Appalachian in the east, the Illinois basin to the south and the Michigan basin to the North, separated by the Cincinnati arch in the middle. An estimate of the storage capacity in the Mount Simon Sandstone was developed using three dimensional regional mapping. Results indicate the potential capacity could range from 9 to 43 Gt [17].
- The United States Geological Survey (USGS) has been undertaking a programme to assess geological reservoirs for CO_2 storage in the US. Task 1 of the activity is underway and is assessing the potential of coal seams in the US to store CO_2 . To date the potential for low ranks coals in the Powder River Basin have been reported; here low rank coals were found to have a much higher potential than initially envisaged. Deep coal beds in the area containing sub bituminous coal could store up to 8 Gt CO_2 [18]. The work is continuing.

- The Texas Bureau of Economic Geology has developed a database of deep saline aquifers in the USA. According to the USGS some two thirds of US States are underlain by saline aquifers which represent a significant potential for CO_2 storage in the USA. The database contains details of the properties of the aquifers and their geographic extent and is designed to provide data that stakeholders can use to evaluate aquifer disposal options [19].

It must be noted that it is difficult to compare geographical storage potentials for each country because the methodologies used to develop these numbers are not based on similar assumptions. It would be appropriate that a standard methodology for storage capacity estimates should be derived, which could be undertaken as part of the IPCC special report process

Geographical Relationship between CO_2 Sources and Geological Storage Sites

Research Project Activities
Within the research projects discussed above a number of projects are making efforts to compare emission sources with storage possibilities in geological storage sites. Estimates of the ‘realisable’ potential are then being made in a number of ways which include estimates based on economic considerations and more simply using relative geographical positioning. The various regions that are being researched in detail are discussed below:

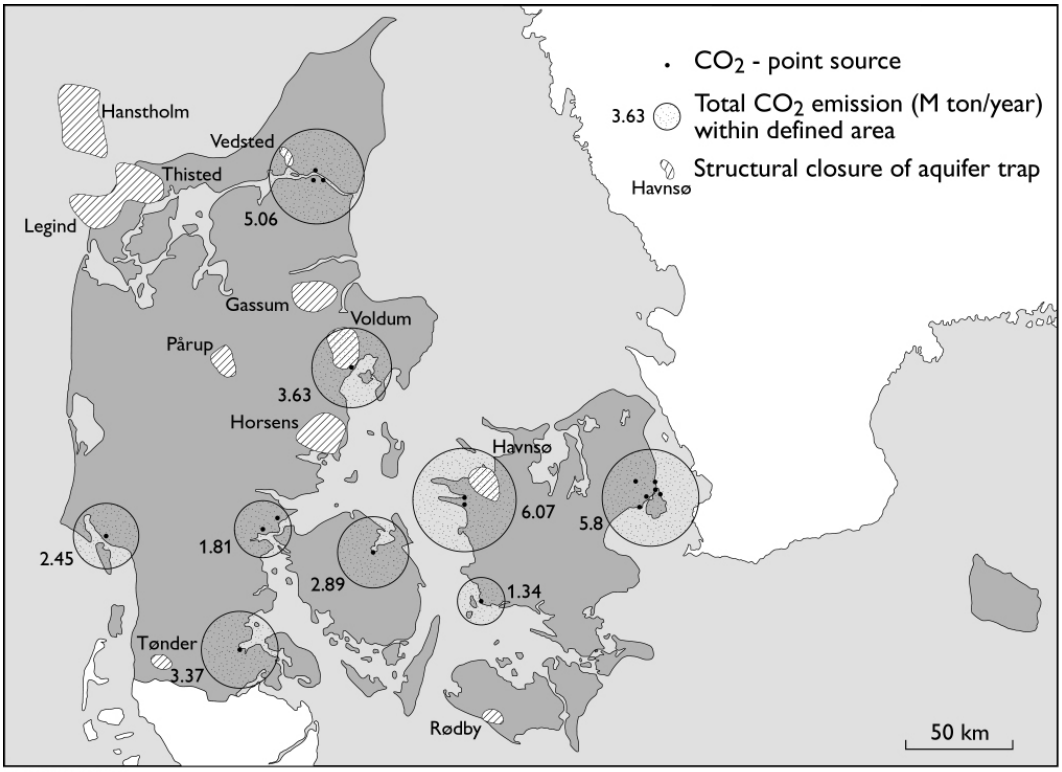
Australia - In 1999 CO_2 emissions from stationary sources in Australia, primarily produced through electricity generation, were 259.8 Mt/y or 56.7% of national emissions. Maps have been made of the location of all the major stationary emission sites, and the likely supply rates of CO_2 for a 20 year period were estimated. The emissions mapping has shown that the top 35 point sources represent 90% of the emissions that can be potentially sequestered and the top 50 point sources represent 96% of the emissions that can be potentially sequestered. The 20 year emissions map shows that the major emissions sources are concentrated into clusters. The occurrence of distinct clusters was considered to be a favourable result in that having the largest emissions sites concentrated into nodes will reduce the infrastructure costs of establishing injection sites, provided that viable injection sites exist in the neighbouring regions. The GEODISC project then undertook a screening study to compare emission sources with storage prospects in sedimentary basins. The study made an estimate of the likelihood that any given site would have the storage capacity to match the anticipated supply rate of CO_2 from neighbouring sources. The result showed a clear dichotomy between Eastern Australia (where there are larger CO_2 sources and reservoirs with low storage capacity) and Western Australia (where there are smaller CO_2 sources and larger storage potential). It was concluded that Australia has the potential to realistically store up to between 100 and 115 Mt CO_2 per year, or 25% of its annual total net CO_2 emissions [6,7].

Canada - Only limited work is underway currently in Canada to match potential storage sites and potential sources. A map of CO_2 emission sources and their proximity to suitable sedimentary basins in Alberta has been developed by the Alberta Energy Board and Alberta Geological Survey. The Alberta Research Council as part of their ongoing study on Enhanced Gas Recovery from Coal Bed Reservoirs will look at opportunities for CO_2 ECBM projects in Alberta. The Clean Coal Power Coalition (CCPC) will also look for prospects for CO_2 ECBM projects linked to power stations in Nova Scotia within the next year. The Geological Survey of Canada on behalf of the CCPC will also look at opportunities for CO_2 storage from power stations in oil and gas fields in Alberta and Saskatchewan in 2003 [9].

Europe - One aspect of the GESTCO project is the development of a Decision Support Software (DSS) tool to facilitate the evaluation of the economics of sequestration systems. The DSS is coupled to a database containing the inventory data [20]. The interface of the DSS is based on a Geographic Information System (GIS) that enables the user to define a CO_2 sequestration system by selecting CO_2 sources, capture technologies and sinks. An economical optimal transportation route is then established connecting the sources with the sinks. The DSS determines first if the storage potential of the selected site is sufficient and if that is the case the costs of each link in the chain is calculated and added to arrive at total cash flow.

Results from the GESTCO project are now becoming available, but the application of the DSS tool to selected sites has not yet been reported. Results will probably be not available until

2004. Some preliminary regional results have been published; one particular case is that for Denmark. Total emissions from large stationary sources in Denmark is 32.4 Mt (90% of which comes from power plants) which amounts to about 50% of the total Danish CO_2 emissions in year 2000. To estimate the total storage capacity in Denmark, nine large deep saline aquifers with structural closures were assessed. Preliminary data suggest that the nine structures alone may provide storage for at least 10 Gt CO_2. By then mapping the major CO_2 point sources in Denmark and their position relative to the aquifers an estimate of the potential ‘realisable’ storage capacity was made (see Figure 4).



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Courtesy of Geological Survey of Denmark and Greenland (GEUS)

Figure 4. Map Showing the Clustering of Major CO_2 Point Sources and Deep Saline Aquifers for Underground Storage in Denmark

Emissions totalling some 14.7 Mt/y CO_2 could be injected into 3 confined structures up to 50 km away from a number of stationary emission sources. In annual emission terms, these injection rates amount to 50% of Denmark’s CO_2 emissions from large stationary sources and 25% of Denmark’s total CO_2 emissions [21]. One storage structure has been studied in detail, the Havnsø structure, which has an estimated storage capacity of 1 Gt CO_2. This structure lies 15 km North West of the town of Kalundborg, which has two stationary sources; a power plant and a refinery. The Havnsø structure is capable of storing all the CO_2 emissions from the power plant and refinery for more than 150 years.

Japan - As discussed earlier, work has not commenced on linking sources and stores in Japan.

USA - A number of activities are underway in the USA that are mapping both the CO_2 emission sources and potential CO_2 storage options. These activities are summarised below.

- The MIDCARB project is based on five US States; Illinois, Indiana, Kansas, Kentucky and Ohio. The project is developing an interactive database that combines data on CO_2 emission sources with potential geological storage prospects in the region and allow the costs of storage to be determined. The aim of the project is to allow stakeholders in those regions to better understand their carbon management options [22].
- As part of their aquifer project, the Texas Bureau of Economic Geology has established a GIS that indicates the position of power stations and aquifer disposal options and the associated costs of storage are determined [19].

- Battelle have developed a GIS package that contains data on major power plants in the US and geological storage options. It will allow the emission sources and storage site options to be matched to determine carbon management prospects in the USA [23].
- Texas Bureau of Economic Geology has also undertaken a project for the Electrical Power Research Institute looking for opportunities to link power stations with oil fields in West Texas for CO_2 EOR Operations. Distance grids of 145 km were fitted around existing power plants using GIS software which indicated that there were substantial opportunities for CO_2 sequestration but supplying them presented a challenge and detailed consideration of a CO_2 supply network would be needed [24].

Investigations to match CO_2 sources with oil fields are not limited to research projects in the USA. Commercial companies like Blue Source LLC which specialises in market matching of CO_2 suppliers and EOR users in the USA [25].

IEA GHG Activities
The IEA Greenhouse Gas R&D Programme (IEA GHG) is undertaking a number of studies to develop detailed cost and capacity estimates for CO_2 storage. In addition, detailed cost estimates for CO_2 capture are now being carried out whilst a cost estimate for CO_2 transmission by pipeline has been completed. Once all these cost estimates have been completed then detailed comparison of CO_2 capture and storage and other mitigation options such as biomass, solar and wind energy will be undertaken.

The first phase of the cost and capacity estimates for CO_2 storage was the development of a baseline study that developed a database of CO_2 emission sources world-wide, which was discussed in Section 2. It is planned to develop the cost and capacity estimates on a regional basis, with the first two regional studies being North America and Europe. The North American study, covering on-shore storage in Canada and USA, will be undertaken in collaboration with Battelle, who have developed a GIS system for the USA (as discussed earlier). Data in the GIS will be extended to include Canadian storage opportunities and industrial emission sources in the USA and Canada. The second study will assess the geological storage potential with the European Union and Norway. This project, which involves members of the GESTCO team, will develop a GIS map of storage in Europe extending the boundaries of the research activities of the GESTCO project to cover the whole of Western Europe. For Europe a significant proportion of the storage potential will be offshore, thus giving a contrast to the North American Study.

Both studies will use GIS maps to compare geographically the main emission sources in the regions of interest with geological storage sites. The work will allow the costs of geological storage to be developed along with regional storage capacity estimates. The studies will also investigate the need for pipeline infrastructure networks in these regions to maximise the 'realisable' storage potential that can be achieved and the likely costs associated with these networks. For long distance storage it is likely that there will be economies of scale in establishing trunk pipelines rather than individual pipelines, as occurs now in the natural gas industry. A pipeline cost calculator developed by IEA GHG to compare the transmission of different energy carriers will be used in these studies [26]. The results of these studies will become available in mid to late 2003.

IEA GHG has also recently completed a study that has investigated potential early opportunities for CO_2 capture and storage based on high concentration CO_2 streams [27]. The aim of the study was to identify opportunities for early implementation of CO_2 capture and storage. This was achieved by matching high purity CO_2 sources with low capture costs to enhanced hydrocarbon production techniques such as CO_2 EOR and, CO_2 ECBM and setting a limit on the transmission distance of up to 100km. The IEA GHG CO_2 emissions sources database provided the source data of high purity CO_2 emission sources which were then incorporated into a GIS along with maps of oil reservoirs and coal seams world-wide, see Figure 5.

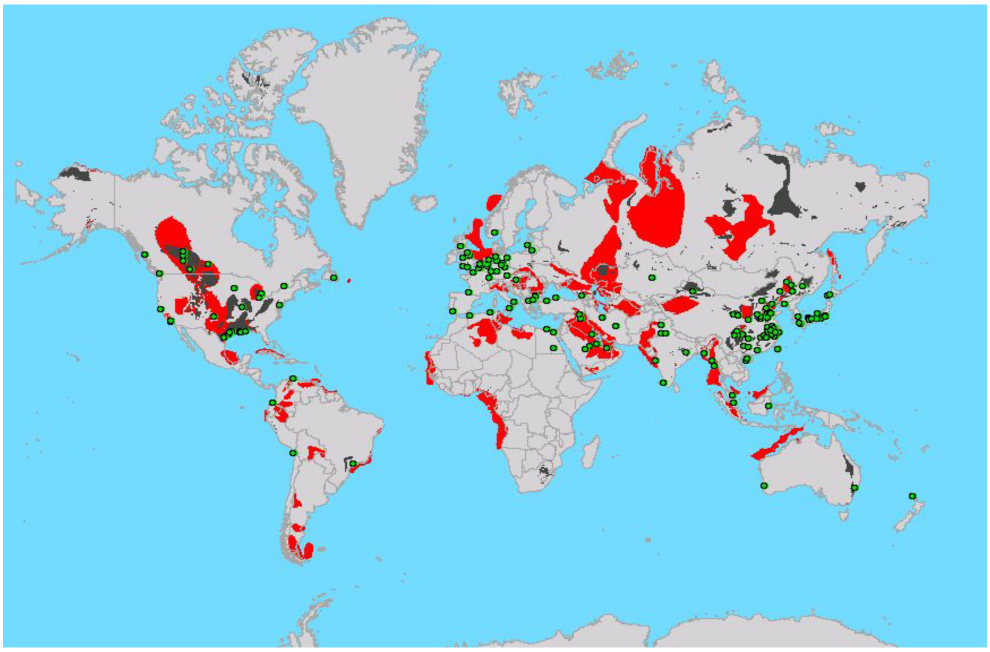

Figure 5. Matching of High Purity Emission Sources (Green dots) with Oil and Coal Occurrences World-wide

The GIS was then used as a tool to match high purity sources with possible storage sites. By applying a cut out at a minimum emission of 100 000 tonnes per year, 198 potential high purity sources were identified. Distance grids of 0-50 km and 50-100 km. were then created around these sources. The GIS was then used to overlay the selected sources onto petroleum and coal field boundaries, which lead to the development of a ‘long list’ of possible projects. The long list contained: 62 CO_2 sources with 409 EOR combinations and 58 CO_2 sources with 78 ECBM combinations [28]. The lists of CO_2 EOR and CO_2 ECBM projects were reduced to a ‘short list’ of projects for further study of their potential for funding by a two-step procedure. First, the best reservoir for each source was selected by means of a simple cost-benefit analysis. Second, a Multi Criteria Analysis was performed. A short list of 15 CO_2 EOR and 15 CO_2 ECBM candidates was then produced. The geographical distribution of the short listed projects was: for CO_2 EOR, 12 of the projects are in North America (USA and Canada), 2 in Saudi Arabia and 1 in Mexico. In the CO_2 ECBM cases, 9 are in China and 6 in Europe. To reduce the short listed projects further, a limited technical assessment of the cases was made and expert opinions sought in each case. From the short list, four cases were selected for detailed analysis: two CO_2 EOR cases and two CO_2 ECBM cases.

The study and methodology employed proved to be a useful exercise to identify potential early opportunities for CO_2 capture and storage that could be implemented under the Kyoto Flexible Mechanisms or by international donor aid grants or commercial investment depending on their location [28].

CO_2 Transportation

For most CO_2 storage opportunities in geological reservoirs, the captured CO_2 will be transported by pipeline. The CO_2 will be transported as a supercritical or dense phase fluid because it is economically favourable in high pressure pipelines [29]. Only if long distance transport of CO_2 (i.e. >1000km) is considered then ships would be used. CO_2 is currently transported by ship but only in very limited quantities, tankers similar to those used to transport liquefied petroleum gas are used [2].

Most of the research activities underway to date have not looked extensively at the need for extensive networks of CO_2 pipelines. It is hoped that the regional work underway by GESTCO and IEA GHG will begin to provide information on the need for pipeline networks in Europe and North America.

There are already in existence large long distance CO_2 pipelines in some regions of the world, although the CO_2 pipeline network is not nearly as extensive as the networks of natural gas pipelines. Currently, there are some 3100 km of large CO_2 pipelines in operation (Figure 6), which have a capacity of 44.7 Mt/y of CO_2, most of which are in the USA [29]. These pipelines supply CO_2 for enhanced oil recovery operations and many have been operating since the early 1980s. To put these numbers in perspective, there are some 536 000 km of major natural gas transmission pipelines in the USA. The CO_2 pipeline network is substantial, but not that big in comparison with the amounts of other gases that are already being transmitted.

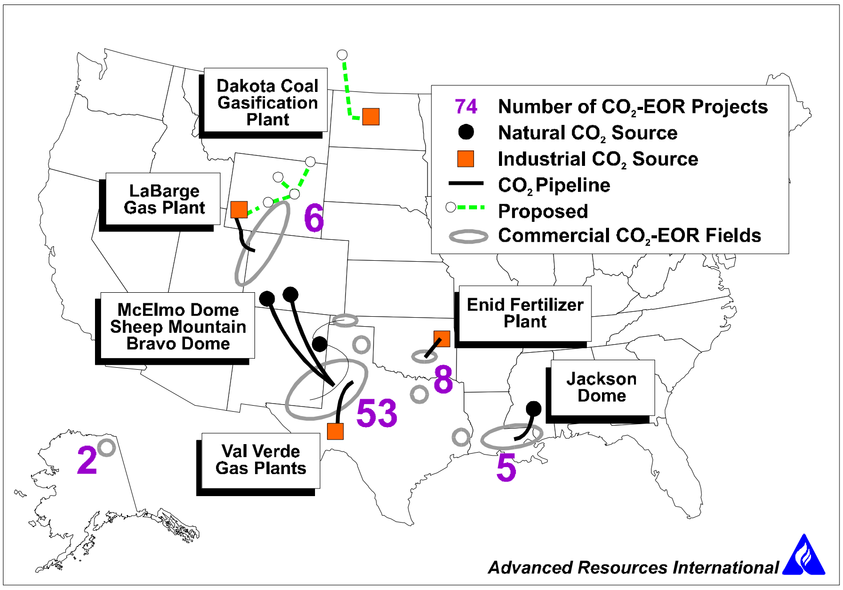

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Figure 6. Locations of Commercial CO_2 EOR Projects in the United States and Existing CO_2 Pipeline Networks

There is a significant knowledge base that has developed based on the experience that has been gained from both the operation and regulation of these pipelines by operators and Federal/State regulatory bodies, in some cases for over 15 years. This knowledge and expertise should be transferable to other areas of the world that are considering the development of CO_2 capture and storage technology and hence the introduction of CO_2 pipelines and CO_2 pipeline networks.

New networks of CO_2 pipelines are now being considered in other regions of the world. In the North Sea, a project called CENS lead by ELSAM and Kinder Morgan (an operator of CO_2 pipelines in the USA) is looking to establish a CO_2 pipeline network linking power plants in Denmark, Norway and the UK to offshore oil fields. The network would link 10 power plants with 12 oil fields over a period of eight years and would supply some 700 million tonnes of CO_2 for CO_2 EOR operations. The pipeline network will comprise 1500 km of CO_2 pipelines offshore together with 900 km onshore in Denmark and the UK. The project aims to take advantage of a window of opportunity for CO_2 EOR in the North Sea that could extend oil and gas production in the North Sea by 15 years or more assuming the economic situation is favourable to the oil producers [30].

Discussion

At the outset the paper set out to answer the question, how much of the emitted CO_2 can be effectively stored within geological reservoirs. The key conclusion must be that the question cannot be fully resolved at this time.

The paper has clearly identified that data on the emission sources of CO_2 world-wide has been collated and that there are many activities currently underway in regions of the world that are assessing the storage potential in geological reservoirs. The work underway to assess storage potentials is focused on some of the regions where there are significant emissions of CO_2 from stationary sources, such as North America and Europe. It is also likely that CO_2 capture and storage when implemented as a mitigation option will be applied in these regions at an early stage in any world-wide implementation schedule. However, equally there are other regions of the world where interest should be focusing on the application of CO_2 capture and storage, but as yet only limited research is underway to assess the geological storage capacities in these regions. These regions include South East Asia (only Japan is undertaking work in this region) and the Indian sub-continent. Research activities, therefore, need to be developed and initiated in these areas of the world. Such activities may need the support of international bodies such as the UN and donor aid agencies.

In addition to the research on storage assessments, work on matching emission sources and geological storage sites is underway so as to gain an appreciation of their respective geographical positioning. This work is essential so that estimates of the ‘realistic’ potential for CO_2 storage in geological structures can be determined and the implications these storage requirements will have in terms of the need for new CO_2 pipeline networks. If large networks of CO_2 pipelines will be needed, as is likely, then careful consideration will be needed to avoid any safety or environmental implications (particularly in densely populated regions), because these could adversely affect public acceptability of the pipelines and the technology as a whole. Fairly extensive CO_2 pipeline networks are operating in North America, with limited safety/environmental problems, although it is noted, these pipelines are routed in sparsely populated regions of the USA and Canada.

It is difficult from the results available to identify further research needs at present, because most of the research work is currently underway and will not be completed until mid to late 2003 or early 2004. After the work is completed it is recommended that a further review is undertaken to identify future research needs. It should be re-emphasised that the research effort currently underway should be expanded to other regions of the worlds where this technology needs to be applied.

It is noted that the present discussion has focused on CO_2 storage as an option to reduce anthropogenic greenhouse gas emissions from existing power plants and industrial facilities. However, in the future consideration for applying this approach of mapping reservoirs could be applied in the planning process for new power/industrial facilities to minimise pipeline requirements and transmission/storage costs. Equally if CO_2 capture and storage from fossil fuels is considered as a stepping stone to a hydrogen economy, then consideration of storage sites could be an important feature in planning new hydrogen production facilities and pipeline networks. Planning new facilities, either power plants or hydrogen plants, with CO_2 storage in mind may enable greater use to be made of available storage capacity in geological reservoirs in the future.

Conclusions

The sources of emissions of CO_2 from stationary sources (power and industrial plants) are well documented on a global basis. Over 14 600 emission point sources have been identified worldwide, with power plants the principal source of CO_2 emissions. North America is the region with the largest number of stationary CO_2 sources (37%) followed by OECD Europe (14%) and China (10%). Globally three large clusters of CO_2 emission sources, in the mid and eastern states of the USA, in central regions of Europe (UK, Netherlands, Germany, Austria, Hungary, Czech Republic) and in South East Asia (eastern China and Japan) can be identified with a further cluster around the Indian sub continent.

Activities to assess the geological storage potential are underway in several regions of the world, namely North America (USA and Canada), Europe, Australia and work is now commencing in Japan. The work on geological storage potential matches some of the areas where clusters of CO_2 emissions were observed notably USA and Europe. However, regions such as South East Asia are not being researched extensively, only Japan is undertaking work in that region and the Indian sub-continent is not being researched at all. There are, therefore, gaps in the assessment activities underway to understand the regional distribution of CO_2 emissions and their potential for storage in geological formations.

In the regions/countries where geological storage potential assessment work is underway, activities are also in progress to gain an awareness of the geographical distribution of the CO_2 emissions and the storage sites. To enable storage capacities to be compared from region to region a standard methodology for estimating storage capacities needs to be agreed. Most probably this can be done as part of the IPCC process. In most cases, this work will not be completed before the end of 2003, the exception being Australia. At this stage it is too early to be able to quantify how much of the available ('theoretical') storage capacity can be accessed economically by pipeline networks and hence how much of the available capacity can be realistically utilised either regionally or globally.

Once the geographical relationship between sources and storage sites is clear then transportation networks for the CO_2 can be considered. Again work now underway should begin to provide information requirements for CO_2 pipeline infrastructure network in regions of the world in late 2003. CO_2 pipeline networks already exist in the USA and Canada, although are much less extensive than natural gas pipeline networks. However, if widespread implementation of CO_2 capture and storage does occur, CO_2 pipelines networks at least as extensive as those for natural gas can be considered in the future.

It is noted that the work underway currently is only considering opportunities for CO_2 sequestration from existing CO_2 sources. In the future should a hydrogen economy develop based initially on fossil fuels with CO_2 storage then the methodologies being developed to map CO_2 sources and storage opportunities could be equally well deployed to match potential sites for hydrogen plants with natural gas pipelines and storage sites to maximise the potential for utilising available storage opportunities for CO_2.

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CO_2 Capture and Reuse

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Abstract

CO_2 capture and storage including its utilization or reuse presents an opportunity to achieve deep reductions in greenhouse gas emissions from fossil energy use. The development and deployment of this option could significantly assist in meeting a future goal of achieving stabilization of the presently rising atmospheric concentration of greenhouse gases.

CO_2 capture from process streams is an established concept that has achieved industrial practice. Examples of current applications include the use of primarily, solvent based capture technologies for the recovery of pure CO_2 streams for chemical synthesis, for utilization as a food additive, for use as a miscible agent in enhanced oil recovery operations and removal of CO_2 as an undesired contaminant from gaseous process streams for the production of fuel gases such as hydrogen and methane. In these applications, the technologies deployed for CO_2 capture have focused on gas separation from high purity, high pressure streams and in reducing (or oxygen deficient) environments, where the energy penalties and cost for capture are moderately low. However, application of the same capture technologies for large scale abatement of greenhouse gas emissions from fossil fuel use poses significant challenges in achieving (at comparably low energy penalty and cost) gas separation in large volume, dilute concentration and/or low pressure flue gas streams. This paper will focus on a review of existing commercial methods of CO_2 capture and the technology stretch, process integration and energy system pathways needed for their large scale deployment in fossil fueled processes. The assessment of potential capture technologies for the latter purpose will also be based on published literature data that are both 'transparent' and 'systematic' in their evaluation of the overall cost and energy penalties of CO_2 capture.

In view of the of the fact that many of the existing commercial processes for CO_2 capture have seen applications in producing streams for use as a feedstock or by product for subsequent utilization in industrial processes, this paper will also review existing methods of CO_2 utilization and the future scope for utilization as a sink that could prevent the release of anthropogenic CO_2 emissions into the atmosphere. In order to be effective as a sink, the process or product that uses CO_2 must take cognisance of the type of energy use, energy penalties and net greenhouse gas emissions associated with the 'capture' and 'fixation' of carbon, as well as significantly prolonging the period between CO_2 production from fossil fuels and the stage of its final discharge into the atmosphere from any degradation or release of the 'fixed' carbon. Hence, the manufacturing of various chemicals, materials or products using CO_2 as a raw material will be reviewed and evaluated in terms of these criteria as well as their chemical / thermodynamic stability relative to CO_2.

Introduction

CO_2 can be captured with available technology but it has only recently been seriously considered as a potential method of reducing emissions. Its importance stems from the fact that, currently, about 85% of the world's commercial energy needs are supplied by fossil fuels. A rapid change to non-fossil energy sources, even if possible, would result in large disruption to the energy supply infrastructure, with substantial consequences for the global economy. The technology of CO_2 capture and storage (including the utilization or reuse of the CO_2 captured) would enable the world to continue to use fossil fuels but with much reduced emissions of CO_2. In view of the many uncertainties about the course of climate change, further development and demonstration of CO_2 capture and storage technologies is a prudent precautionary action

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This paper provides an overview of technologies for capture and reuse of CO_2.

Sources and purity of CO_2 streams

Capture of CO_2 is best carried out at large point sources of emissions, such as power stations, oil refineries, petrochemical and gas processing plants, steel works and large cement works. These industries emit large quantities of CO_2, as shown in table 1 (data for 1994-1996) (IEA GHG 1999a, IEA GHG 1999b, IEA GHG 2000a, IEA 1998).

Table 1 CO_2 emissions by major industries

	CO_2 emissions, Mt/y
Power generation	7660
Iron and steel production	1440
Cement production	1130
Oil refining	690
Petrochemicals	520

Emissions of CO_2 from power generation increased to 8900 Mt/y in 2000 (IEA, 2002). As power generation is the main source CO_2, that is the focus of discussion of CO_2 capture options but the opportunities to capture CO_2 from the other large point sources are also discussed.

CO_2 can be captured either from flue gases or from process streams before combustion. Typical CO_2 concentrations in theses streams are shown in table 2 (IEA GHG, 1999a, IEA GHG, 2000a, IEA GHG, 2000b).

Table 2 CO_2 concentrations

	CO_2 concentration, vol.%
Power station flue gas:	
Coal fired boiler	14
Natural gas fired boiler	8
Natural gas combined cycle	4
Coal-oxygen combustion	>80
Power station, pre-combustion capture of CO_2	
Coal gasification fuel gas	40
Natural gas partial oxidation fuel gas	24
Blast furnace gas:	
Before combustion	20
After combustion	27
Cement kiln off-gas	14-33
Oil refinery and petrochemical plant fired heaters	8

How Can CO_2 be Captured?

There are three main techniques for capture of CO_2 in power generation:

- Post-combustion capture
- Pre-combustion capture
- Oxy-fuel combustion

Post combustion capture

The CO_2 concentration in power station flue gas ranges from about 4% (by volume) for natural gas fired combined cycle plants to about 14% for pulverized coal fired boilers. Natural gas contains less carbon than coal and natural gas combined cycle power plants have higher thermal efficiencies than coal fired plants. The quantity of CO_2 produced per MW of electricity generated is therefore half about as much in a natural gas combined cycle plant as in a coal fired plant but the volume of flue gas is about two thirds greater (IEA GHG 2000b).

Flue gas could be compressed and stored underground but the energy required for compression would be very large and the underground reservoirs would quickly become full. It is therefore necessary to separate the CO_2 from the flue gas.

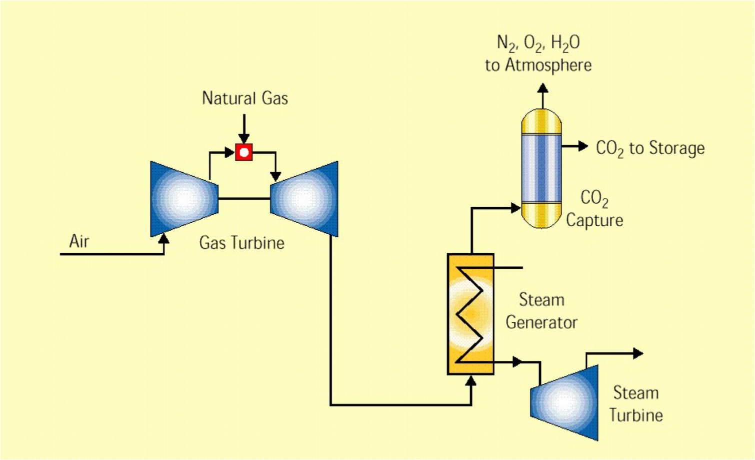

Figure 1 Gas turbine combined cycle with post-combustion capture of CO_2

A variety of techniques, described later, can be used to separate CO_2 from flue gases. The best proven technique at present is to scrub the flue gas with an amine solution. The amine from the scrubber is heated by steam to release high purity CO_2 and the CO_2 free amine is then reused in the scrubber. Figure 1 is a simplified diagram of a gas turbine combined cycle power station with post-combustion capture of CO_2. Post-combustion capture can also be applied to coal and oil fired power stations but some additional measures are needed to minimize contamination of the CO_2 capture solvent by impurities in the flue gas, such as sulphur and nitrogen oxides. In many respects, post-combustion capture of CO_2 is analogous to wet flue gas desulphurisation (FGD) techniques, which is widely used on coal and oil fired power stations to reduce emissions of SO_2.

Pre-combustion capture

The low concentration of CO_2 in power station flue gas means that a large volume of gas has to be handled, which results in large equipment sizes and high capital costs. A further disadvantage of the low CO_2 concentration is that powerful chemical solvents have to be used to capture CO_2 and regeneration of the solvents to release the CO_2 requires a large amount of energy. If the CO_2 concentration and pressure could be increased, the CO_2 capture equipment would be much smaller and different physical solvents could be used, with lower energy penalties for regeneration. This can be achieved by pre-combustion capture.

The fuel is reacted with oxygen or air, and in some cases steam, to give mainly carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO_2 and more hydrogen. The CO_2 is separated and the hydrogen is used as fuel in a gas turbine combined cycle plant. The process is, in principle, the same for coal, oil or natural gas, but when coal or oil are used there are more stages of gas purification, to remove particles of ash, sulphur compounds and other minor impurities. Figure 2 is a simplified diagram of a coal fired power plant with pre-combustion capture of CO_2.

Although pre-combustion capture involves a more radical change to the power station design, most of the technology is already proven in ammonia production and other industrial processes. This type of process, without CO_2 capture, is already used in several commercial scale IGCC (integrated gasification combined cycle) plants fuelled by coal, residual oil and petroleum coke but these plants do not yet have long continuous operating times. With the addition of CO_2 capture, one of the novel aspects is that the fuel gas feed to the gas turbine is essentially hydrogen. The hydrogen will be diluted using nitrogen or steam to reduce emissions of nitrogen oxides from the gas turbine combustors. It is expected that it will be possible to burn hydrogen in an existing gas turbine with little modification but this is not demonstrated technology. At least two of the large gas turbine manufacturers are known to have undertaken tests with the objective of establishing criteria for the combustion of hydrogen-rich fuels (IEA GHG 2000b).

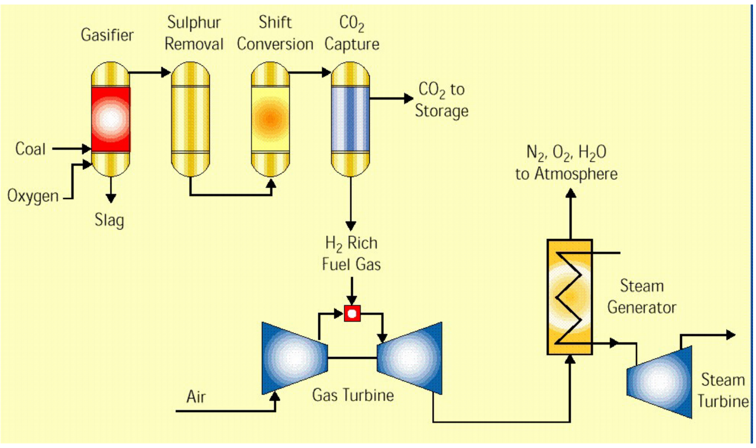

Figure 2. Coal fired IGCC with pre-combustion capture of CO_2

The hydrogen produced in pre-combustion capture processes could alternatively be used to generate electricity in a fuel cell. Fuels cells are currently not economically competitive with gas turbines, but they may become more competitive in future, particularly for small-scale distributed power generation. The technology of capture and storage is therefore expected to be suitable for future as well as current power generation technologies.

Oxyfuel combustion

The concentration of CO_2 in flue gas can be increased greatly by using concentrated oxygen instead of air for combustion, either in a boiler or gas turbine. The oxygen would be produced by cryogenic air separation, which is already used on a large scale, for example in the steel industry. If fuel is burnt in pure oxygen, the flame temperature is excessively high, so some CO_2-rich flue gas would be recycled to the combustor to make the flame temperature similar to that in a normal air-blown combustor. The advantage of oxygen-blown combustion is that the flue gas has a CO_2 concentration of around or above 80%, compared to 4-14% for air blown combustion, so only simple CO_2 purification is required. It may be possible to omit some of the flue gas cleaning equipment which currently has to be included in power stations, such as flue gas desulphurisation, which would reduce the net cost of CO_2 capture (Andersson, 2002). Some sulphur compounds and some other impurities would remain in CO_2 fed to storage, which may be acceptable in some circumstances. The oxygen and CO_2 recycle combustion process has also a further benefit in suppressing NOx formation with attendant benefits in the post combustion removal of NOx. The disadvantage of oxyfuel combustion is that a large quantity of oxygen is required, which is expensive, both in terms of capital cost and energy consumption. Advances in oxygen production processes, such as new and improved membranes that can operate at high temperatures could improve overall plant efficiency and economics. Oxyfuel combustion aimed at power generation applications has so far only been demonstrated in small scale test rigs. Larger scale applications have seen use in glass and steel melting furnaces.

Oxyfuel combustion could be an attractive option for retrofit of existing steam cycle power stations. The modifications that would need to be made at the power station would be relatively minor and in some places supplies of oxygen could be obtained from existing commercial air separation plants.

Oxyfuel combustion could also be applied to gas turbines or for the conversion of fuel gas fed to fuel cells. However, gas turbines that use CO_2 as the working fluid would be substantially different to conventional gas turbines that use air and retrofit of existing gas turbines would not be feasible. Substantial investment would be needed to develop an oxygen fired gas turbine and there would need to be the prospect of a large market to persuade manufacturers to make such an investment. Novel gas turbine and fuel cell based cycles involving oxyfuel combustion and condensation of CO_2 have been proposed. Such cycles could be attractive, but they would involve even more development work.

Types of CO_2 Capture Technology

Chemical solvent scrubbing

Currently the favoured method for removal of CO_2 from flue gases uses chemical solvents. The most common solvent used for removing CO_2 from low pressure flue gas is monothanolamine (MEA). Prior to CO_2 removal the flue gas is cooled and particulates and other impurities are removed as far as possible. It is then passed into an absorption vessel where it comes into contact with the chemical solvent, which absorbs much of the CO_2 by chemically reacting with it to form a loosely bound compound. The CO_2-rich solvent from the bottom of the absorber is passed into another vessel (stripper column) where it is heated with steam to reverse the CO_2 absorption reactions. CO_2 released in the stripper is compressed for transport and storage and the CO_2-free solvent is recycled to the absorption vessel. CO_2 recovery rates of 98% can be achieved, although around 90% capture is normally proposed for power stations, and product purity can be in excess of 99% (Wilson, 1992).

Amine scrubbing technology has been established for over 60 years in the chemical and oil industries, for removal of hydrogen sulphide and CO_2 from gas streams. This experience is largely on natural gas streams and/or with chemically reducing (primarily oxygen deficient) gases but there are several facilities in which amines are used to capture CO_2 from flue gas streams today, one example being the Warrior Run coal fired power station in the USA, shown in figure 3, where 150 t/d of CO_2 is captured.

The main concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities, high solvent degradation rates from reaction with SO_2 and NO_2 and the large amounts of energy required for regeneration. These factors generally contribute to large equipment, high solvent consumption and large energy losses. New or improved solvents with higher CO_2 absorption capacities, faster CO_2 absorption rates, high degradation resistance and low corrosiveness and energy use for regeneration are needed to reduce equipment sizes and capital and operating costs.

Figure 3. CO_2 capture plant at Warrior Run power station (courtesy AES)

Physical solvent scrubbing

The conditions for CO_2 separation in pre-combustion capture processes will be different from those in post-combustion capture processes. The feed to the CO_2 capture unit in a coal-based IGCC process, located upstream of the gas turbine, would have a CO_2 concentration of about 35-40% and a total pressure of at least 20 bar. The CO_2 partial pressure is therefore at least 50 times higher than in post-combustion capture. In pre-combustion capture it may be preferable to use different types of solvents, known as physical solvents, which combine less strongly with CO_2. The advantage of such solvents is that CO_2 can be separated from them in the stripper mainly by reducing the pressure, resulting in much lower energy consumption. The main physical solvents that could be used for CO_2 capture are cold methanol (Rectisol process), dimthylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor process) and sulpholane. Physical solvent scrubbing of CO_2 is well established, e.g. in ammonia production plants.

The technology development needs for physical solvents are similar in principle to those for chemical solvents, in particular the need for higher efficiency gas-liquid contactors and solvents with lower energy requirements for regeneration.

Adsorption

Some solid materials with high surface areas, such as zeolites and activated carbon, can be used to separate CO_2 from gas mixtures by adsorption. The process operates on a repeated cycle with the basic steps being adsorption and regeneration. In the adsorption step, gas is fed to a bed of solids that adsorbs CO_2 and allows the other gases to pass through. When a bed becomes fully loaded with CO_2, the feed gas is switched to another clean adsorption bed and the fully loaded bed is regenerated to remove the CO_2. In pressure swing adsorption (PSA), the adsorbent is regenerated by reducing pressure. In temperature swing adsorption (TSA), the adsorbent is regenerated by raising its temperature and in electric swing adsorption (ESA) regeneration takes place by passing a low-voltage electric current through the adsorbent.

PSA and TSA are used commercially for gas separation and are used to some extent in hydrogen production and in removal of CO_2 from natural gas. ESA is not yet commercially available but it is said to offer the prospect of lower energy consumptions than the other processes. Adsorption is not yet considered attractive for large-scale separation of CO_2 from flue gas because the capacity and CO_2 selectivity of available adsorbents is low. However, it may be successful in combination with another capture technology. Adsorbents that can operate at higher temperatures in the presence of steam with increased capacity and improved selectivity are needed.

Membranes

Gas separation membranes rely on differences in physical or chemical interactions between gases and a membrane material, causing one component to pass through the membrane faster than another. Various types of membrane are currently available, including porous inorganic membranes, palladium membranes, polymeric membranes and zeolites. Membranes cannot usually achieve high degrees of separation, so multiple stages and/or recycle of one of the streams is necessary. This leads to increased complexity, energy consumption and costs. Several membranes with different characteristics may be required to separate high-purity CO_2. Membranes could be used to separate CO_2 at various locations in power generation processes, for example from fuel gas in IGCC or during combustion in a gas turbine.

Gas absorption membranes are micro porous solids that are used as contacting devices between a gas and a liquid. The CO_2 diffuses through the membrane and is removed by an absorption liquid such as amine, which selectively removes certain components. In contrast to gas separation membranes, it is the absorption liquid, not the membrane that gives the process its selectivity.

Much development is required before membranes could be used on a large scale for capture of CO_2 in power stations.

Cryogenics

CO_2 can be separated from other gases by cooling and condensation. Cryogenic separation is widely used commercially for purification of CO_2 from streams that already have high CO_2 concentrations (typically >90%). It is not normally used for more dilute CO_2 streams, although it has recently been claimed that CO_2 can be captured (by freezing it as a solid) from atmospheric pressure flue gases with energy losses similar to those of other techniques. A major disadvantage of cryogenic separation of CO_2 is the amount of energy required to provide the refrigeration necessary for the process, particularly for dilute gas streams. Another disadvantage is that some components, such as water, have to be removed before the gas stream is cooled, to avoid blockages and freezing in heat exchangers. Cryogenic separation has the advantage that it enables direct production of liquid CO_2, which is needed for certain transport, such as transport by ship. The most promising applications for cryogenics are expected to be for separation of CO_2 from high pressure gases, such as in pre-combustion capture processes, or oxyfuel combustion in which the input gas contains a high concentration of CO_2.

Other techniques

The need to capture CO_2 may make some radically different power generation technologies attractive. One such technology is chemical looping combustion, in which direct contact between the fuel and the combustion air is avoided by using a metal oxide to transfer oxygen to the fuel in a two-stage process (Copeland, 2001). In the reduction reactor, the fuel is oxidised by reacting with a metal oxide, which it converted to a lower oxidation state. It is then transported to a second reactor, the oxidation reactor, where it is re-oxidised by reacting with O_2 in the air. The major development issue associated with chemical looping combustion is development of a metal oxide material that is able to withstand long-term chemical cycling and is resistant to physical and chemical degradation from impurities generated from fuel combustion.

Efficiencies and Costs of CO_2 Capture

Efficiencies and costs of new coal and natural gas fired power stations with and without CO_2 capture are summarized in tables 3 and 4 (IEA GHG, 2000b, EPRI, 2000, Muramatsu, 2002). These reference studies are based on the current state of the art for CO_2 capture and significant improvements are expected in future, as described later.

Table 3a Performance of pulverized coal-fired power stations

Data source	Capture solvent	Steam conditions	Efficiency, LHV Without capture	 With capture	 Capture penalty
IEA GHG	MEA	310bar, 593˚C Double reheat	45.6	33.0	12.6
EPRI/DOE	MEA	345bar, 649˚C Double reheat	44.8	32.5	12.3
Muramatsu	MEA	250bar, 600˚C Single reheat	42.5	32.2	10.3
Muramatsu	KS-1	250bar, 600˚C Single reheat	42.5	34.8	7.7

Table 3b Performance of coal-fired IGCC power stations

Data source	Gasifier	Gas turbine	Efficiency, LHV Without capture	 With capture	 Capture penalty
IEA GHG	Shell (dry-feed)	9FA	46.3	38.2	8.1
EPRI/DOE	E-Gas (slurry)	7H	45.2	38.8	6.4

Table 3c Performance of gas-fired combined cycle power stations

Data source	Capture system	Gas turbine	Efficiency, LHV Without capture	 With capture	 Capture penalty
IEA GHG	Pre-combustion	9FA	56.2	48.3	7.9
IEA GHG	Post-combustion	9FA	56.2	47.2	9.0
EPRI/DOE	Post-combustion	7FA	55.6	43.5	12.1

Table 4 Capital costs of power stations with and without CO_2 capture

Data source	Fuel	Plant type	Capital cost, $/kWe		
			Without capture	With capture	Capture penalty
IEA GHG	Coal	Pulverised coal, MEA capture	1020	1860	830
EPRI/DOE	Coal	Pulverised coal, MEA capture	1160	1940	780
IEA GHG	Coal	IGCC, Shell	1470	2200	730
EPRI/DOE	Coal	IGCC, E-Gas	1260	1640	380
IEA GHG	Gas	Combined cycle, MEA capture	410	790	380
EPRI/DOE	Gas	Combined cycle, MEA capture	510	1010	500
IEA GHG	Gas	Combined cycle, pre-combustion	410	910	500

The energy penalties and capital costs for CO_2 capture in these studies are broadly consistent, bearing in mind the different plant design bases.

The IEA GHG studies show that the energy penalties and costs for pre and post combustion capture of CO_2 in natural gas combined cycle plants are broadly similar. The IEA GHG and EPRI/DOE studies both show that the energy penalty for pre-combustion capture in coal fired IGCC plants is significantly lower than for post combustion capture in pulverised coal plants using MEA solvent.

The results of the study by Muramatsu show the efficiency benefits of a novel solvent for post-combustion CO_2 capture. This solvent is being used for commercial CO_2 recovery from the flue gas of a steam reformer in an ammonia plant (Mimura, 2000).

The cost of CO_2 capture in IGCC depends strongly on the type of gasifier. Gasifiers that feed the fuel as a water slurry and which involve quenching the product gas with water are expected to show lower incremental energy penalties and costs for CO_2 capture than gasifiers which feed the coal as a dry powder and which use a high temperature heat recovery boiler, as they already produce a raw fuel gas containing the steam required for the subsequent shift conversion of CO to H_2 and CO_2. Slurry feed / quench gasifiers also tend to have lower capital costs but they have lower thermal efficiencies, either with or without capture, so they may not necessarily be the best choice overall. A new study by IEA GHG, not yet published, predicts that the energy penalty for CO_2 capture and compression would be 9.4 percentage points for dry-feed (Shell) gasifier IGCC and 7.3 percentage points for slurry-feed (Texaco) gasifier IGCC. It also predicts that the capital cost penalty for capture will be $520/kW for a dry-feed gasifier (more optimised than the one given in tables 3 and 4) and $320/kW for a slurry-feed gasifier. An efficiency penalty of only 2.0% for CO_2 capture in a slurry-feed gasifier IGCC has been claimed but this does not include CO_2 compression and only 75% of the CO_2 is captured, compared to 85-90% in the other studies (O'Keefe 2001).

The plants described in table 3 include CO_2 compression to a pressure of 84 bar (EPRI/DOE), 110 bar (IEA GHG) or 139 bar (MHI). In the IEA GHG study plants, CO_2 compression accounts for a thermal efficiency penalty ranging from 1.6 percentage points for the gas fired plant with pre-combustion capture, to 3.2 percentage points for the coal fired plant with post-combustion capture.

Overall costs of CO_2 capture

The costs of CO_2 capture in terms of c/kWh or $/t of CO_2 are mainly a function of the energy loss and the capital cost. The costs in these two studies should therefore be broadly similar. However, different economic conventions, such as fuel costs, rates of return of capital result in significantly different results. To simplify the presentation, costs are presented based on IEA GHG's standard economic assessment criteria, which include a 10% discount rate, 25 year plant life and base load operation (85-90% load factor depending on the technology).

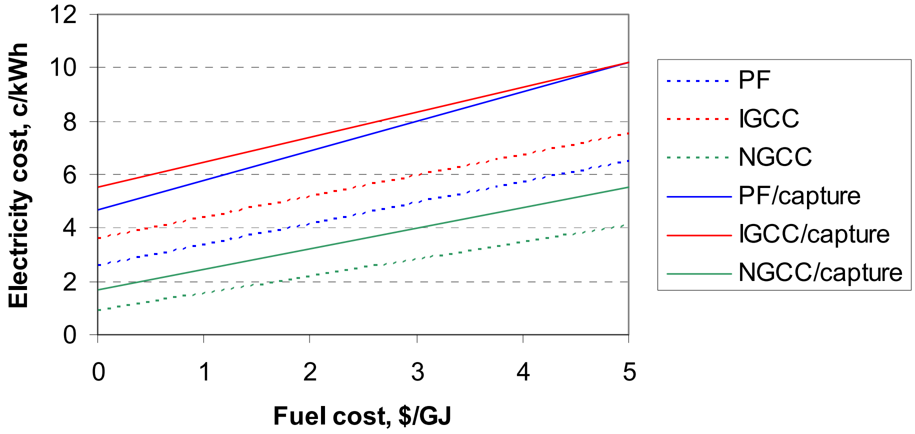

Figure 4 Costs of electricity generation with and without CO_2 capture

Costs of electricity generation with and without CO_2 capture at a range of fuel prices are shown in figure 4. At a gas cost of $2/GJ, CO_2 capture increases the cost of gas fired electricity generation by 1.1 c/kWh, or 50%. CO_2 capture increases the cost of electricity generation in a pulverized coal plant by 2.6 c/kWh or 70% and by 2.1 c/kWh or 45% in an IGCC plant. At typical fuel prices these costs in c/kWh would translate into a capture cost of about $40 per tonne of CO_2 avoided and is broadly similar for both gas and coal-fired power plants. These costs exclude the costs of CO_2 storage, which depends on how the CO_2 is stored and the distance between the capture and storage sites. A cost of US$10/tonne of CO_2 stored would add 0.9c/kWh to the cost of electricity from a pulverized coal plant and 0.4c/kWh to the costs from a natural gas combined cycle plant.

The data given above are for new power stations at greenfield sites. CO_2 capture could also be applied as a retrofit to existing power stations. However, when the efficiency of the existing power plant without CO_2 capture is relatively low, combined with reduced opportunities for better energy integration of the capture plant, the energy penalty for CO_2 capture represents a greater proportion of the net power output. In a study on retrofit of CO_2 capture to an existing power station in the USA, the efficiency of the power station was 38.7% (LHV basis) without CO_2 capture, 23.2% with MEA scrubbing, 25.5% with combined MEA/MDEA scrubbing and 25.5% with oxy-fuel firing (Nsakala, 2001).

Potential for performance and cost improvements

Much of the technology for CO_2 capture has been demonstrated, although not in large power stations, but there is significant scope to reduce costs and energy losses in future.

The studies referred to in tables 3 and 4 are based on the current state of the art for CO_2 capture. For post-combustion capture with solvent scrubbing, novel solvents based on sterically hindered amines or formulated amines are being developed, which should be able to substantially reduce energy requirements, by 40% compared to MEA in the case of formulated solvents (Chakma, 1998). The KS-1 solvent referred to in table 3a is a hindered amine and even more efficient solvents are being developed.

The heat required to regenerate amine solvent in a power station is provided by low pressure steam extracted from the steam turbine. There are opportunities to significantly reduce the overall energy penalty for solvent scrubbing by optimised heat integration between the steam cycle of the power station and the solvent regeneration.

Capital and non-fuel operating costs are also being addressed. High efficiency, low cost gas-liquid contactors are being developed to reduce equipment sizes and costs. For traditional MEA scrubbing, the loss of amine solvent due to degradation and vapour and mist loss can be significant (around 2kg/t CO_2) resulting in high operating expenses. Changes to the solvent, mechanical devices and operating conditions have greatly reduced solvent losses to around 0.35 kg/tCO_2 (Mimura 2002).

Experience with analogous technologies for back end cleaning of emissions from power stations such as flue gas desulphurisation (FGD) and selective catalytic reduction (SCR), indicates that the costs of CO_2 capture could be reduced significantly in future. Costs of FGD and SCR have halved over a 20 year period since they started to be applied at a large scale (Rubin 2002). Provided research and development is carried out and there are market incentives to apply the technology at a large scale, similar cost reductions may be achieved for CO_2 capture. Breakthroughs in new CO_2 capture technologies could result in even larger cost reductions.

IGCC power plants are usually more expensive than conventional steam cycle plants at present but costs are decreasing. This will help to reduce the net cost of CO_2 capture using this route.

As well as improvements to current capture technologies there is also the possibility of technological breakthroughs, which could greatly reduce the costs and energy penalties for CO_2 capture. If there is a large established market for CO_2 capture plants, the incentives for companies to develop new technologies will be increase. Various novel CO_2 capture technologies are at an early stage of development, as described earlier. New technologies for oxygen production, such as membranes, are being developed which could be significant benefits for both oxygen blown IGCC and oxy-fuel combustion processes. In the long-term, high efficiency fuel cells may become competitive for power generation. Including CO_2 capture in power plants with solid oxide fuel cells may be relatively simple (Dijkstra, 2002).

CO_2 Capture from Other Large Point Sources

Power generation is the largest source of CO_2, which could be captured and stored. However, substantial quantities of CO_2 could also be captured in some large energy consuming industries. Emissions and the CO_2 concentration in process streams from these industries are shown in tables 1 and 2.

Iron and steel production

About 60% of global steel production is from primary integrated steel mills but these mills account for over 80% of CO_2 emissions from steel production (IEA GHG, 2000a). About 70% of the carbon input to an integrated steel mill is present in the blast furnace gas, which is used as fuel gas within the steel mill. Blast furnace gas typically contains 20% by volume CO_2 and 21% CO, with the rest being mainly N_2; its pressure is typically 2-3 bar. CO_2 could be captured before or after combustion of this gas. The CO_2 concentration after combustion in air would be about 27% by volume, significantly higher than in the flue gas from power stations. The higher flue gas CO_2 concentration can reduce the energy penalty of capture depending on the type of CO_2 capture technology deployed. Other process streams within a steel mill may also be suitable candidates for CO_2 capture, before or after combustion, for example the off-gas from an oxygen-steel furnace contains typically 70% CO and 16% CO_2. New direct reduction processes for iron and steel production are being developed; these would also be suitable for CO_2 capture.

Cement production

CO_2 originates in cement production from two different sources: raw material and fuel. Process-related CO_2 is formed during the calcinations process, where $CaCO_3$ is converted to CaO and CO_2. CO_2 is also produced from combustion of fuel, which is necessary to heat the materials up to their reaction temperature and to provide the endothermic heat of reaction. Process-related CO_2 normally accounts for more than half of the total CO_2 emissions and this proportion is expected to increase in future due to energy efficiency improvements. The flue gas from cement kilns contains between 14 and 33 vol% CO_2, depending on the production process and type of cement (IEA GHG, 1999a). The CO_2 concentration is higher than in power generation processes, so cement kilns could be suitable for CO_2 capture. CO_2 could be captured using amine scrubbing but the large quantities of low grade heat required for amine regeneration are not normally available at cement works. Combined heat and power plants would have to be built at the site to provide the heat. It may be possible to use oxyfuel combustion in cement kilns but the effects of a higher CO_2 concentration in the flue gas on the process chemistry would need to be assessed. Existing cement kilns in developing countries such as China and India are often relatively small but the quantity of CO_2 produced by a new large cement kiln can be similar to that of a power station boiler.

Oil refining

About 65% of the CO_2 emissions from oil refineries are from fired heaters and boilers (IEA GHG, 1999b). The exhaust gases from these heaters and boilers are similar to the flue gases in power stations, so CO_2 could be captured using the same techniques and at broadly similar costs. The same would be true for major fired heaters in the petrochemical industry, such as ethylene cracking furnaces.

Hydrogen and ammonia production

Large quantities of hydrogen are produced by reforming of natural gas, mainly for production of ammonia-based fertilizers. CO_2 separated in hydrogen plant is normally vented to the atmosphere but it could instead be compressed for storage. This would be a relatively low cost method of avoiding release of CO_2 to the atmosphere. It could also provide useful opportunities for demonstration of CO_2 transport and storage techniques.

Natural gas purification

Some natural gas fields contain substantial amounts of CO_2. The CO_2 concentration has to be reduced to ~2.5% for pipeline transmission, so any excess CO_2 has to be separated. The captured CO_2 is usually then vented to the atmosphere but, instead, it could be stored in underground reservoirs. The first example of this being done on a commercial scale (see figure 5) is the Sleipner Vest gas field in the Norwegian sector of the North Sea (Torp, 2002).

Energy carriers for distributed energy users

A large amount of fossil fuel is used in transport, e.g. cars or aircraft, and in small-scale heat or power production. It is not practicable using current technologies to capture, collect, and store CO_2 from such small scale dispersed users. Nevertheless, large reductions could be made in CO_2 emissions through use of a carbon-free energy carrier, such as hydrogen or electricity. Both hydrogen and electricity are often considered as a carrier for energy from renewable sources. However, they can also be produced from fossil fuels, using capture and storage technology to minimize release of CO_2. Production of hydrogen or electricity from fossil fuels with CO_2 storage could be an attractive transitional strategy to aid the introduction of future carbon free energy carriers.

Figure 5. Oil and gas production facilities in the Sleipner field, (Courtesy of Statoil)

CO_2 Reuse

This section will review existing and new ways for the utilization or reuse of CO_2 captured from industrial processes to better understand its potential role in reducing anthropogenic emissions into the atmosphere.

Industrial Use of CO_2

CO_2 captured from process streams are used in food processing and carbonation, for synthesis of chemicals such as urea, methanol, organic and inorganic carbonates and as a solvent - the largest use of which is in CO_2 enhanced oil recovery (CO_2 EOR).

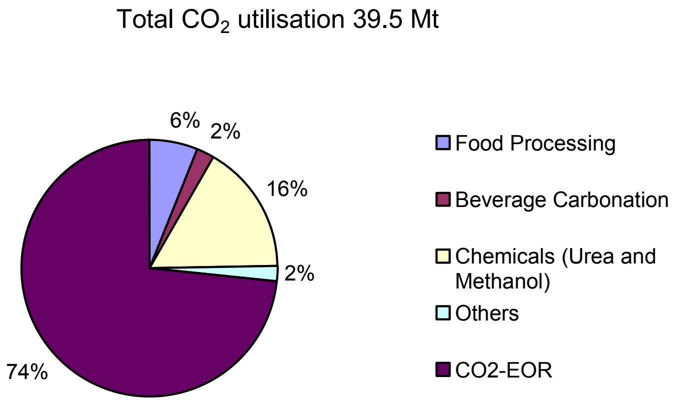

Figure 6 Annual US CO_2 utilization in 1989 (IEA WPFF, 2000)

Estimates published by the IEA WPFF, 2000 suggest that in the USA in1989, a total of the 4.7 Mt was consumed in the form of liquid/solid CO_2, out of which the food processing industry consumed around 2.7 Mt/year. The cooling of food, especially ice cream, meat products, and frozen foods, was the principal use for both solid and liquid CO_2. However, in this application, carbon dioxide is utilized in an open cycle, which after evaporation to achieve cooling is vented back into the atmosphere. It is estimated that the average residence time before re-release of CO_2 into the atmosphere is about 1-2 weeks, depending upon the food product refrigerated.

CO_2 used in food processing is normally sourced from its excess production from fossil fuel based ammonia and hydrogen production plants or recovery from fermentation processes. The same source of data (IEA WPFF, 2000) suggests approximately 0.9 Mt/year of CO_2 is used for beverage carbonation in the USA, with soft drinks and beer production consuming the largest quantity. The average residence time before CO_2 is released into the atmosphere depends upon when the beverage is consumed, usually in a matter of a few days.

Urea, methanol and other chemical manufacturing consume around 6.5 Mt/year of CO_2 (IEA WPFF, 2000; Kirk and Othmer, 1993). While methanol can potentially be used in a closed cycle, prolonging the release of CO_2 back into the atmosphere, urea once it is spread in soil, decomposes and CO_2 is released without further fixation. Other uses such as the production of dimethyl carbonate (DMC), CO_2 based alkylene polycarbonate, metal processing etc consume around 0.7 Mt/year of CO_2. More recent estimates for chemical utilization of CO_2 published in 1995 suggest that global consumption for chemical synthesis is 89 Mt/year (IEA GHG, 1995).

CO_2 enhanced oil recovery (CO_2 EOR) where CO_2 is used as a miscible solvent is a growing utilization option. Around 28 Mt/year of CO_2 was consumed in 1998 in the USA for CO_2 EOR (Stevens 2000).

Thermodynamic stability of CO_2

The chemical conversion of reactants to products usually occurs because it is thermodynamically favorable - the reactants move from a higher to a lower energy state i.e. from a less stable to a more chemically stable form. Therefore, developing an understanding of the relative stability of a CO_2 to chemicals that could be produced from it would provide knowledge of the conditions necessary to promote CO_2 utilization or reuse.

Gibbs free energy of formation is a measure of the energy state and chemical stability of a compound. The Gibbs free energy of formation of some chemical compounds and CO_2 are shown in table 5. The lower and more negative the value the Gibbs free energy of formation of a carbon containing compound relative to CO_2, the more stable it is relative to CO_2 and likely to be readily formed using CO_2 as the initial reactant. The reaction leading to the formation of the more stable compound will also be exothermic i.e. resulting in a net release of energy.

Table 5. Gibbs free energy of formation, ΔG^o for CO_2 and other chemicals (Lide, 2001)

Chemicals	Free Energy of Formation ΔG^o_{298} (kJ/mole)
Higher Paraffin Waxes	-----
Acetylene C_2H_2 (*g*)	+209
Benzene C_6H_6 (*g*)	+130
Ethylene C_2H_4 (*g*)	+68
Propylene C_3H_6 (*g*)	+62
Methane CH_4 (*g*)	-51
Carbon Mono-oxide CO (*g*)	-137
Methanol CH_3OH (*g*)	-162
Ethanol C_2H_5OH (*g*)	-168
Urea NH_2CONH_2 (*s*)	-197
H_2O (*g*)	-228
H_2O (*l*)	-237
Acetic Acid CH_3COOH (*l*)	-374
Carbon Dioxide CO_2 (*g*)	-394
Dimethyl Carbonate DMC (*s*)	-492
Silicon dioxide SiO_2 (*s*)	-805
Magnesium Carbonate $MgCO_3$ (*s*)	-1012
Calcium Carbonate $CaCO_3$ (*s*)	-1129

Table 5 also shows that CO_2 is chemically more stable (higher minus ΔG^o) than most common hydrocarbons and provides a ready explanation as to why we burn fossil fuels to produce energy with CO_2 as the most stable end product. Thus for the long-term storage (by utilization) of CO_2 from its conversion into a chemical we should ideally produce chemicals such as the organic and inorganic carbonates shown in Table 5. This is because there is energy release from the chemical reaction with no further net input of fossil energy and thus more CO_2 emissions that may otherwise reduce the amount of carbon captured or 'fixed'. The produced chemical should also have a long shelf life in order to be effective as an abatement measure to prevent climate change. If on the other hand we were to produce a carbon based chemical from CO_2 with a more positive value of ΔG^o the net storage or use of CO_2 will only occur if the energy used for chemical synthesis results in lower emissions of CO_2 than consumed by the reaction when derived from a fossil fuel, or if it originates from an entirely carbon free source such as renewable or nuclear energy.

Carbon and energy cycle for CO_2 utilization

Smith and Thambimuthu, 1991 proposed a simple carbon free energy cycle for CO_2 utilization shown in figure 7. In this approach the CO_2 captured from a power plant or industrial process is converted into a carbon based fuel or chemical using non-fossil energy input such as solar or nuclear energy for example. As noted in the previous section this approach to the synthesis of fuels and chemicals with higher and more positive value of ΔG^o relative to CO_2 provides a means to slow the growth of fossil energy use with utilization of the carbon fixed as a fuel (followed by the continuous recycling of carbon dioxide) or with permanent fixation of carbon when producing a chemical with a more permanent shelf life. Overall, the cycle proposed for energy use and carbon fixation and utilization essentially mimics the pathway followed by the natural use of solar energy for biomass growth, its utilization and re-growth in a terrestrial carbon cycle.

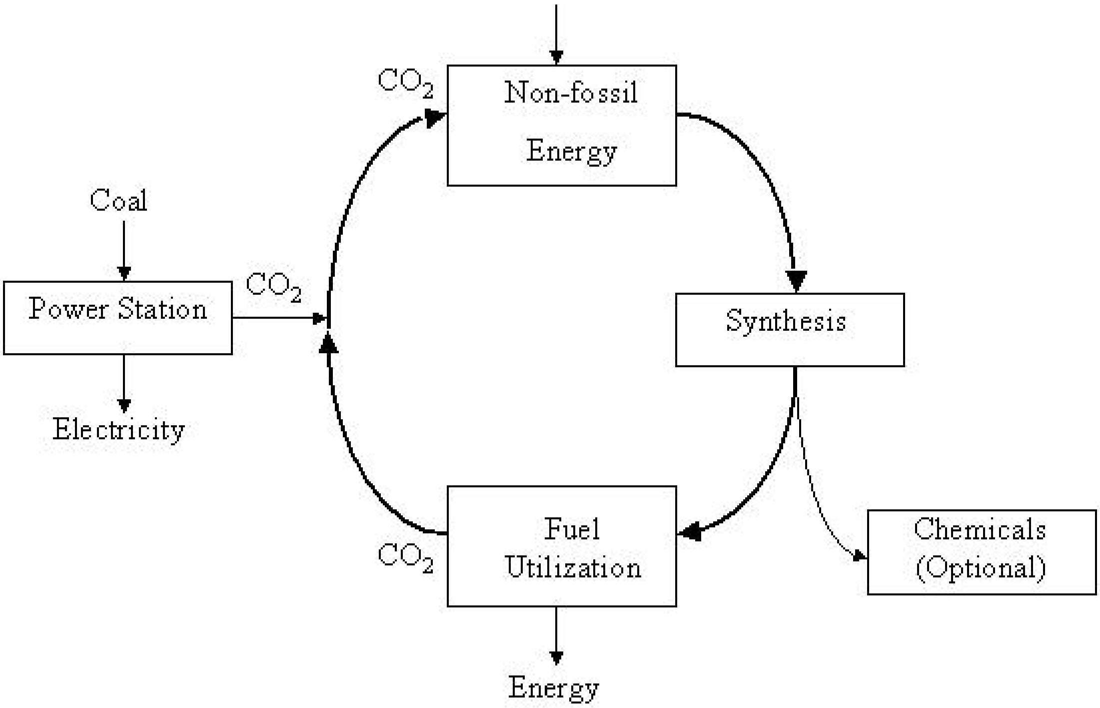

Figure 7 A CO_2 based secondary energy cycle (Smith and Thambimuthu 1991)

Figure 8 shows a much more comprehensive strategy for the utilization or reuse of fossil fuel derived CO_2 emissions. This approach treats CO_2 emissions derived from the industrial use of fossil fuels *in a closed loop* or with its storage away from the atmosphere from the following perspectives:

- Establishment of a carbon (CO_2) neutral secondary energy cycle
- Utilization and/or recycling of carbon (CO_2) in secondary material cycles
- and long-term utilization/storage of fossil fuel derived CO_2

The proposed pathways are described in greater detail below.

Carbon neutral secondary energy cycle

In this cycle, the CO_2 from fossil sources can be reduced for example into fuels such as methane (Nishiguchi et al, 1998) methanol (Sano et al, 1998) or carbohydrates as follows in endothermic or energy consuming reactions:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta G^o_{298} = 113.6 \text{ kJ/mol} \qquad (1)$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \qquad \Delta G^o_{298} = 3.9 \text{ kJ/mol} \qquad (2)$$

$$nCO_2 + nH_2O \rightarrow C_nH_{2n}O_n + nO_2 \quad \Delta G^o_{298} = (+)\text{ve (endothermic)} \qquad (3)$$

While equation (3) represents natural photosynthesis for the production of sugars (and hence biomass) in the presence of sunlight, equations (1) and (2) involve the synthetic reduction of carbon dioxide and require energy input in some other form. Additionally these reactions would involve consumption of hydrogen, which has to be generated from water with input of non fossil fuel derived energy. Overall, this cycle (see figure 8) which produces energy with CO_2 recycling in *a closed loop* requires a non fossil based energy supply (such as from renewables or nuclear energy) and effectively uses the carbon derived from anthropogenic CO_2 emissions as a carrier of this energy. The capacity and residence time of carbon in this cycle will depend upon the supply and conversion efficiency of non-fossil energy. Higher the supply and conversion efficiency of this energy source, higher will be the capacity of this cycle to hold carbon for a longer duration and in preventing the net accumulation of CO_2 in the atmosphere. If the CO_2 is converted with input of renewable energy, the scheme also provides a convenient means of providing for the intermediate storage and distribution of renewable energy.

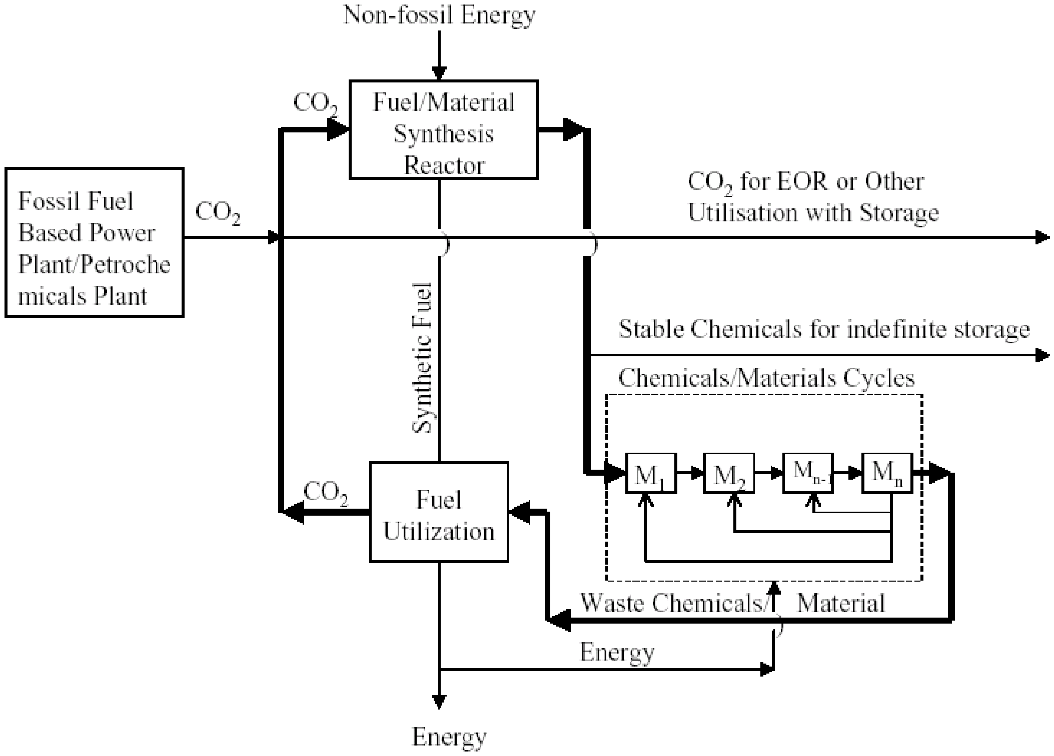

Figure 8 A comprehensive CO_2 and secondary energy utilization strategy

Utilization of carbon in secondary material cycles
As shown in figure 8, in this secondary material cycle, the secondary energy cycle discussed in the previous section is integrated with chemicals/materials processing where carbon dioxide is used as raw material in synthesis of intermediate or fine chemicals and other commodity materials. Examples of chemicals and commodity materials that can be synthesized from CO_2 are given below.

Intermediate or fine chemicals for the chemical industry
Aresta, 1998 and Arakawa, 1998 have reported a broad range of intermediate chemicals, which can be synthesized from carbon dioxide. These chemicals include lower and higher hydrocarbons, methane, formic acid, aromatics etc.

Methanol
Methanol synthesis from H_2/CO_2 has been studied in relation to that from H_2/CO (Arakawa, 1998). The context for this work arose from the observation that an addition of small amount of CO_2 into a H_2/CO feed improves methanol yield significantly in the industrial production of methanol (Arakawa, 1998). Rozovskii, 1984 showed by tracer analysis studies that carbon species of methanol produced using various kinds of metal catalysts, originated from CO_2 - suggesting methanol was produced via CO_2 as an intermediate species. The overall penalty for driving this reaction from CO_2 as opposed to CO is the net consumption of an additional H_2 molecule. The methanol produced through this route can be used as a fuel or can be used as an intermediate raw material for the manufacture of various value added chemicals such as formaldehyde resins. These resins are used extensively as household and automotive commodities. This option will fix carbon for a longer time and will substantially reduce the alternate sourcing of these materials from the direct conversion of fossil fuels.

Lower paraffins
Perfect hydrogenation of CO_2 to methane as shown in equation (1) is not difficult. Various kinds of metal catalysts are available for this kind of reaction. Ni-La_2O_3-Ru on ceramic fiber support is known to be an efficient and rapid conversion catalyst (Arakawa, 1998).

Although selective and effective synthesis of C_2-C_5 paraffins by direct hydrogenation is more difficult, indirect processes can provide promising routes for their selective synthesis from CO_2 (Arakawa, 1998).

Lower olefin synthesis
Lower olefins such as ethylene and propylene are very important raw materials for the synthesis of many chemicals such as polyethylene, propylene and ethylene oxide. Selective synthesis of lower olefin by direct hydrogenation of CO_2 is relatively difficult in a similar manner as that noted for selective lower paraffin synthesis. However, lower olefins have been successfully synthesized using Fe-K/Alumina catalyst (Arakawa, 1998).

Liu et al., 1999 have proposed a non-thermal plasma approach for the formation of lower olefins from methane and CO_2:

$$2CO_2 + 2CH_4 \rightarrow 2CO + C_2H_4 + 2H_2O \qquad \Delta G^o_{1073\,K} = 35 \text{ kJ/mol} \quad (4)$$

At 1073 K, equilibrium yields of ethylene are fairly high at 57% (Liu et al., 1999). However, the experimental yield over metal oxide catalysts was not sufficiently high (less than 9%).

Additionally, propylene and various aromatics such as Benzene, Toluene and Xylene (BTX) mixtures have been synthesized by reducing CO_2 with propane (Arakawa, 1998). These types of reactions are well known and use the Mobil HZSM-5 series of catalysts. The best reported performance has been achieved with Zn-ZSM-5 which has a conversion of 71.4% of propane to over 43% aromatic products.

Dimethyl carbonate (DMC)
Recent environmental concerns over processing of phosgene and dimethyl sulphate have led to the increased interest in the alternative use of CO_2 for DMC production. DMC is used as a solvent and as a motor fuel octane booster.

Aresta and Galatola, 1999 have reported application of a life cycle analysis (LCA) to DMC manufacturing. It was found that the synthesis route based on phosgene has an environmental impact four times higher than the synthesis route based on CO_2. However the total utilization potential of CO_2 in DMC synthesis is very limited. For example, when used as an octane booster CO_2 consumed in DMC production is released back into the atmosphere without its recycling in a closed loop.

Commodity materials
The intermediate chemicals discussed above are basically raw materials in the production of fuels or other commodity materials. The later option carries higher possibility of ‘fixing’ carbon for a longer duration before it is released back into the atmosphere. One of the promising uses of long-term CO_2 fixation is in the form of CO_2 polymers (IEA GHG, 1995). Although CO_2 is normally not regarded as a useful monomer, it can take part in a number of reactions, particularly to form alkylene oxides and alklyne polycarbonates. The reaction normally involves an organometallic such as diethylzinc together with a hydrogen donor in the form of water, amine or an aromatic dicarboxylic acid. These products are basically used as binders in the electronic industry and are being developed for film applications in the food and medical areas. The predicted market at the current level of development however is only around 100 t/year. However, with further advancement in synthesis of these polymers, they could easily help substitute conventional commodity and engineering polymers such as polyethylene based low density polyethylene (LDPE), high density polyethylene (HDPE) and poly propylene (PP) which are currently manufactured from the direct use of fossil fuels to produce ethylene and propylene. The current market for these polymers is about 50 Mt/year.

Alkylenes synthesized through alkane reduction by CO_2 (as discussed in the previous section) are also basic raw materials in the manufacture of conventional polymers. Alkylene monomers obtained from CO_2 reduction of alkanes can be used in bulk polymerization and will thus help fix carbon. These polymers are stable and carry a long life cycle. Additionally they can be easily converted to lower grade plastics or can be recycled several times. Thus the overall life span of the carbon fixed in this form can be prolonged significantly.

Nishiguchi et al., 1998 have reported another novel technique of reducing CO_2 from large electric power plants to graphitic carbon via methane by catalytic fixation in a membrane reactor:

$$CH_4\,(g) + CO_2\,(g) \Leftrightarrow 2C\,(s) + 2H_2O\,(l)\ \Delta G^o_{298} = -12.1\ \text{kJ/mol} \qquad (5)$$

Overall, this reaction is exothermic. Furthermore, the amount of CH_4 available globally as natural gas is sufficient to be used as a fuel and as a reductant for CO_2. Therefore this process can decrease the amount of CO_2 released permanently, as the graphite is a highly stable and dense form of carbon that can be used in numerous applications (Kirk and Othmer, 1978). However, the abatement potential of this approach will depend on the market for graphite and competition from methane use as a fuel source and raw material for direct chemical synthesis.

Another route for the direct utilization of CO_2 as a commodity material is its application in closed loop refrigeration cycles (Robinson et al., 1998; Taylor, 2002; Brown et al., 2002). CO_2 was widely used as a refrigerant of choice in the 1950's before being replaced by chlorofluorocarbons (CFCs). Due to the environmental impact of CFCs in depleting the ozone layer and the advent of the Montreal Protocol phasing out the global use of CFCs both as a refrigerant and industrial chemical, the air-conditioning industry subsequently switched to the use of hydrofluorocarbons (HFCs) as refrigerants. However, because HFCs are greenhouse gases with a global warming potential of about 1300 times that of CO_2 (Brown et al., 2002), the refrigeration industry is now in the process of evaluating the re-introduction of CO_2 as a more environmentally friendly substitute for HFCs. Between 1994-1997, five European automotive manufacturers and four automotive suppliers participated in a project to investigate the feasibility of CO_2 use in refrigeration cycles for automotive air conditioning systems (Brown et al., 2002). It has been found in this work that the volumetric refrigerating capacity of CO_2 is about five times that of R-22 (CHF_2Cl; Robinson et al, 1998). However the operation of CO_2 at supercritical pressures requires the use of compact high pressure tubing. With recent developments in the production extremely thin high pressure aluminium tubing, CO_2 based refrigeration cycles could emerge as an alternative option for the automotive industry and in other industrial applications.

The chemical, material synthesis and utilization routes proposed in this section have various stages (see dotted box in figure 8). Each stage has a life and after that the chemical/material can be either transformed to a lower grade material or can be recycled back to synthesize a higher grade product. Materials can be incinerated to generate energy as long as the carbon dioxide is fed back into the cycle for its reuse in a closed loop.

Long-term utilization/storage of CO_2

As shown in figure 8, the objective of this route is to permanently remove the CO_2 captured from fossil fuel consumption by diverting it, following its utilization, into isolated long-term storage from the atmosphere. Approaches by which CO_2 storage can be used efficiently with its co-utilization are described below.

CO_2 enhanced oil recovery

Application of conventional oil extraction techniques in existing reservoirs yields only a fraction of the original oil in place. However, the use of CO_2 EOR can increase the oil recovery in a reservoir by 10-15% (IEA GHG, 1995 and 2001). About 30 Mt/year of CO_2 is already used in more than 74 EOR projects in the USA and elsewhere. In these applications the injected CO_2 returning with the produced oil is usually separated and re-injected back into the reservoir to minimize operating costs. The process if repeated to the end of oil recovery in the reservoir, would result in more permanent containment of all the CO_2 used in EOR operations.

The current source of CO_2 used in CO_2 EOR projects is mainly from natural underground reservoirs of CO_2. However, it is possible to use CO_2 captured from fossil fired power plants if the cost of the product delivered on site is competitive with CO_2 recovered from natural reservoirs. The Weyburn CO_2 EOR project in Canada is an example of a scheme where all of the CO_2 is supplied from gas captured and pipelined from the North Dakota coal gasification plant (anthropogenic emissions from fossil fuel use) located approximately 300 km away in the USA.

EOR projects could sequester 120 Gt of CO_2 at a net saving (see figure 9 below) (IEA GHG, 2000c). This economic estimate has assumed an oil price of \$15/bbl. It is noted that the oil price has a significant impact on EOR profitability. Higher oil prices would significantly reduce the net cost of storage. It should be noted that the costs of CO_2 capture from anthropogenic sources and pressurization are not included in Figure 9.

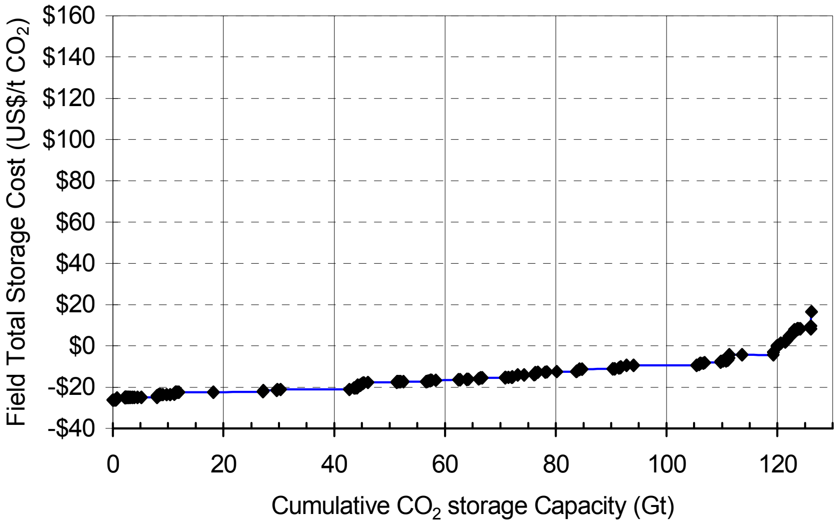

Figure 9 Net costs of CO_2 storage in enhanced oil recovery

Storage of carbon dioxide in magnesite

Mineral ores containing magnesium or calcium can be chemically combined with carbon dioxide to form chemically more stable carbonates. In general the magnesium bearing minerals are more efficient in reactions with CO_2 (Klaus et al, 1997). The overall reaction is either the carbonation of forsterite:

$$\tfrac{1}{2}\,Mg_2SiO_4 + CO_2 \rightarrow MgCO_3 + \tfrac{1}{2}\,SiO_2 \qquad \Delta G^o_{298} = -95 \text{ kJ/mole} \qquad (6)$$

or the carbonation of serpentines:

$$1/3\ Mg_3Si_2O_5(OH)_4 + CO_2 \rightarrow MgCO_3 + 2/3\ SiO_2 + 2/3\ H_2O \quad \Delta G^o_{298} = -64 \text{ kJ/mole} \qquad (7)$$

As can be seen from equations 6 and 7, both reactions are exothermic. More importantly, both reactions are thermodynamically favourable at low temperatures.

As can be seen from figure 10, the Gibbs free energy of the reaction favours the formation of carbonates until at the some elevated temperature, when the equilibrium shifts towards the formation of free carbon dioxide. However, for the technique to be effective for the net storage of anthropogenic CO_2, overall energy use and any accompanying CO_2 emissions associated with this energy use in mining, crushing, processing and removal of the carbonate material for storage must be factored into the overall analysis.

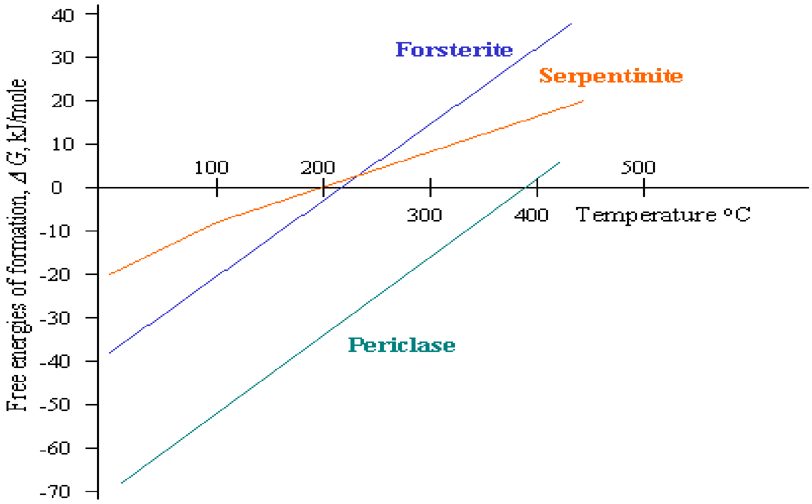

Figure 10 Free energy of formation as function of temperature for the carbonation of periclase (MgO), of forsterite (Mg_2SiO_4) and serpentinite ($Mg_3Si_2O_5(OH)_4$). All energies are normalized to one mole of CO_2

Conclusion

This paper presents a status review of technologies and options for the capture and reuse of anthropogenic CO_2 emissions. Where available, information is presented on the cost of CO_2 capture from industrial processes but with data noticeably absent in the published literature on the cost of CO_2 utilization or reuse in applications other than in EOR.

CO_2 could be captured in power stations and large energy consuming industries such as iron and steel, cement and petrochemicals production and oil refining. CO_2 could also be captured during the production of hydrogen from fossil fuels and this could provide a means to introduce large scale infrastructure for use of hydrogen as an energy carrier for distributed and mobile energy users.

CO_2 can be captured from the flue gases produced by combustion of fossil fuels using the available technology of amine solvent scrubbing. This technology is being improved and significant reductions in costs and energy losses should be possible. Alternative methods of capturing CO_2 are being developed, including combustion using oxygen and capture of CO_2 from fuel gas prior to combustion. Novel CO_2 separation technologies, including membranes, solid adsorbent and cryogenics are also being developed.

Based on current technologies, the cost of capturing CO_2 in a power station would be equivalent to around 1-3 USc/kWh, depending on the type of fuel, the type of power generation, CO_2 capture technology and economic parameters. The cost would be about $40/tonne of CO_2 emissions avoided for both coal and gas fired power plants.

Schemes and potential options for the reuse of CO_2 captured from industrial processes include the manufacture of fuels, intermediate chemicals, commodity materials, mineral carbonates or storage following utilization in EOR. Options for the utilization of CO_2 in fuels and chemicals synthesis are evaluated relative to the thermodynamic properties of CO_2 that determine energy use for its conversion as a reactant. It is noted that most fuels and chemicals with the exception of some organic and mineral carbonates that can permanently ‘fix’ CO_2, are thermodynamically less stable end products that require a net input of energy for the conversion of CO_2. For CO_2 reuse as fuels and chemicals with net energy input, a scheme involving the use of a carbon free energy source would be a requirement to achieve the net abatement of anthropogenic greenhouse gas emissions. In the absence of more detailed information on energy use, process yields and cost of the various schemes reviewed, CO_2 reuse (the exception being in EOR) to achieve deep reductions in anthropogenic greenhouse gas emissions is difficult to assess. It was also found that current industrial utilization of CO_2 is approximately two to three orders of magnitude lower than the net anthropogenic emissions into the atmosphere.

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Geological storage, including costs and risks, in saline aquifers

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Abstract

Capture and storage of CO_2 can in the short to medium term play a part in sequestering already concentrated CO_2 streams, such as from natural gas treatment or ammonia or hydrogen production plants. In the longer perspective CO_2 storage may provide an important route to achieve the deep reductions in greenhouse gas emissions to atmosphere to possibly limit anthropogenic climate change. This is believed to be good news for an increasing global population and the global economy -as well as the oil and gas industry- into the 21st century.

The first decision to apply underground storage of carbon dioxide captured from natural gas -as a climate change mitigation effort- was taken by Statoil (operator) and partners in the Sleipner North Sea licence in 1990. The second such decision was taken by Statoil (operator) and a different set of partners in the Snøhvit licence in the Barents Sea in the autumn of 2001. Sleipner has been injecting CO_2 from 1996 while the Snøhvit project will start up in 2006. At Sleipner the CO_2 is both extracted and injected offshore in a highly permeable sandstone formation, the Utsira formation 1000 meters below the seabed. Utsira is overlain by 800 meters of much denser rock.

The CO_2 injection at Sleipner has been keenly studied in a broadly based, multinational R&D effort, the so-called SACS (Saline Aquifer CO_2 storage programme). In the Snøhvit case the there will be no surface installations offshore and the CO_2-rich natural gas will be sent to shore in a 160 kilometre long pipeline to be processed in an LNG (Liquefied Natural Gas) plant. After removal the CO_2 is sent back to the field in a separate pipeline and be injected in a separate formation under the natural gas field itself.

The paper will also discuss the safety aspects of CO_2 storage in saline aquifers as well as costs associated with CO_2 storage.

Background

Ten years after the 1992 UN Conference on Environment and Development in Rio, it is generally accepted that anthropogenic emissions of greenhouse gases are causing changes in the climate. The major contributor is carbon dioxide (CO_2), which arises mainly from use of fossil fuels. Measures, such as improved energy efficiency and use of alternative energy sources, will help reduce emissions. However, considering that about 85% of the world's commercial energy needs are met by fossil fuels, a rapid move away from oil, natural gas and coal is unlikely to be achievable without serious disruption to the global economy. Today it is starting to be recognised that emissions of CO_2 from fossil fuel combustion could be much reduced by its capture and safe storage in geological formations. Capture and storage of CO_2 can in the short to medium term play a part in sequestering already concentrated CO_2 streams, such as from natural gas treatment or ammonia and hydrogen production plants. In the longer term underground CO_2 storage may provide an important route to achieve the deep reductions in greenhouse gases that seems to be required to limit anthropogenic climate change.

The first decision to apply underground storage of carbon dioxide (CO_2) captured from natural gas - as a climate change mitigation effort - was taken by Statoil (operator) and partners in the Sleipner North Sea licence in 1990. Another similar decision was taken by Statoil (operator) and partners in the Snøhvit licence in the Barents Sea in the fall of 2001. Based on ten years of studies, laboratory research and pilot plant tests, Statoil in cooperation with the Norwegian Government are now discussing taking CO_2 capture to the more difficult task of power generation. Detailed plans for the erection of an industrial scale CO_2 capture demonstration plant on Statoils Kårstø gas terminal has been proposed as part of a national programme.

What should we look for in aquifer storage?

Underground CO_2 storage of any kind must take place in sedimentary rocks. Only they are porous enough to have storage capacity of interest. Figure 1 gives a global overview of the World's sedimentary basins. These are also the only places where coal, oil and natural gas are to be found.

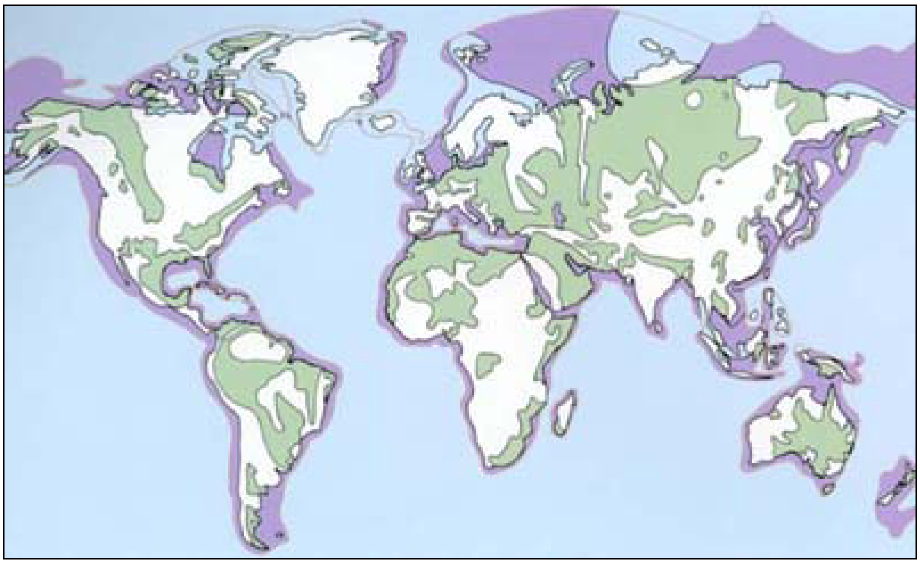

Figure 1. Sedimentary basins of the world. Onshore basins are shown in green. Offshore basins are in lavender (source: Slumberger)

The suitability of saline aquifers for CO_2 storage within these basins will vary widely. In order to achieve large storage capacities underground, CO_2 should be stored above supercritical pressure (supercritical point at 31°C, 74 bar) and deeper than 800 meters below the surface. At these pressures CO_2 is very compressible and will typically have a density of 600 to 800 kilograms per cu.meter. This means that CO_2 will be boyant and tend to move upwards less strongly than natural gas, but more strongly than oil. Storage in a saline aquifer means that we do not have the same assurance as in oil and natural gas reservoirs that there is a closure capable of preventing the upward migration of CO_2. On the other hand these are structures that for the same reasons will not have been penetrated by a large numbers of oil and gas wells in the past.

A saline aquifer for CO_2 storage needs to have a reasonably good porosity and a less porous roof preventing upward mobility. Also it needs to have a reasonable size in order to prevent pressure build up. A closure, which prevents CO_2 from spreading under the roof, may at first sight be seen as required. The experience from and modeling of the Sleipner injection, which does not rely on horizontal closure, indicates that the spreading distances will be limited. The injected CO_2 will over time dissolved into the brine, become heavier than the fresh brine and tend to sink to the bottom of the aquifer. The possibility also exists to dissolve the CO_2 in brine before or as part of the injection process. In this case the injected fluid would be heavier than the surrounding brine and tend to settle to the bottom of the aquifer. This possibility should be researched more closely.

Some aquifers will contain rock, especially silicates rich in calcium, magnesium and iron that will tend to react with the injected CO_2 to form carbonates giving storage a very high degree of permanence. There may also be problems connected to such chemical reactions, as they may tend to lower the injectivity of the wells. National regulations for underground injection will be important for insuring safe and reliable CO_2 storage. Industry will be able to give valuable input, such as the 'Manual of Best Practice' that is now being written by the SACS project (see below). In order to make the concept of CO_2 storage in aquifers more real and show how different circumstances may be even for seemingly similar schemes, I will below describe the existing Sleipner CO_2 storage scheme and the future Snøhvit CO_2 injection.

The Sleipner CO_2 injection

In the time between the Brundtland Commission's UN-report 'Our Common Future' (1987) and the Rio Conference, Statoil began exploring for ways out of the dilemma for oil and natural gas in a possibly climate driven, 21st century world. At first the concept of underground storage was a matter of curiosity. Could it be done? Could it be made safe? What would it cost? Soon, however, it became apparent that underground storage of carbon dioxide was one of the ways forward that ought to be pursued with some vigour.

Around 1990 the Statoil operated Sleipner West offshore gas-condensate field were being planned. A small technical team proposed offshore removal of carbon dioxide from the natural gas which contains about 9% CO_2 - too much to be sold without treatment. The CO_2 to be removed amounts to one million tons per year, or nearly 3% of the Norwegian CO_2 emissions at that time. The technical team therefore was influenced by the discussions taking place in the Norwegian Parliament about climate change and a possible national carbon tax (introduced in 1991). They therefore proposed that the removed CO_2 should be injected for permanent storage into a deep saline aquifer underlying the Sleipner installations. After some discussion with the field partners, this became the approved solution. When the field came on stream in October 1996, the field concept contained not only a massive offshore CO_2 removal plant - a world first -, but also the world's first CO_2 storage in a saline aquifer (the Utsira formation) 1000 meters below the sea bottom.

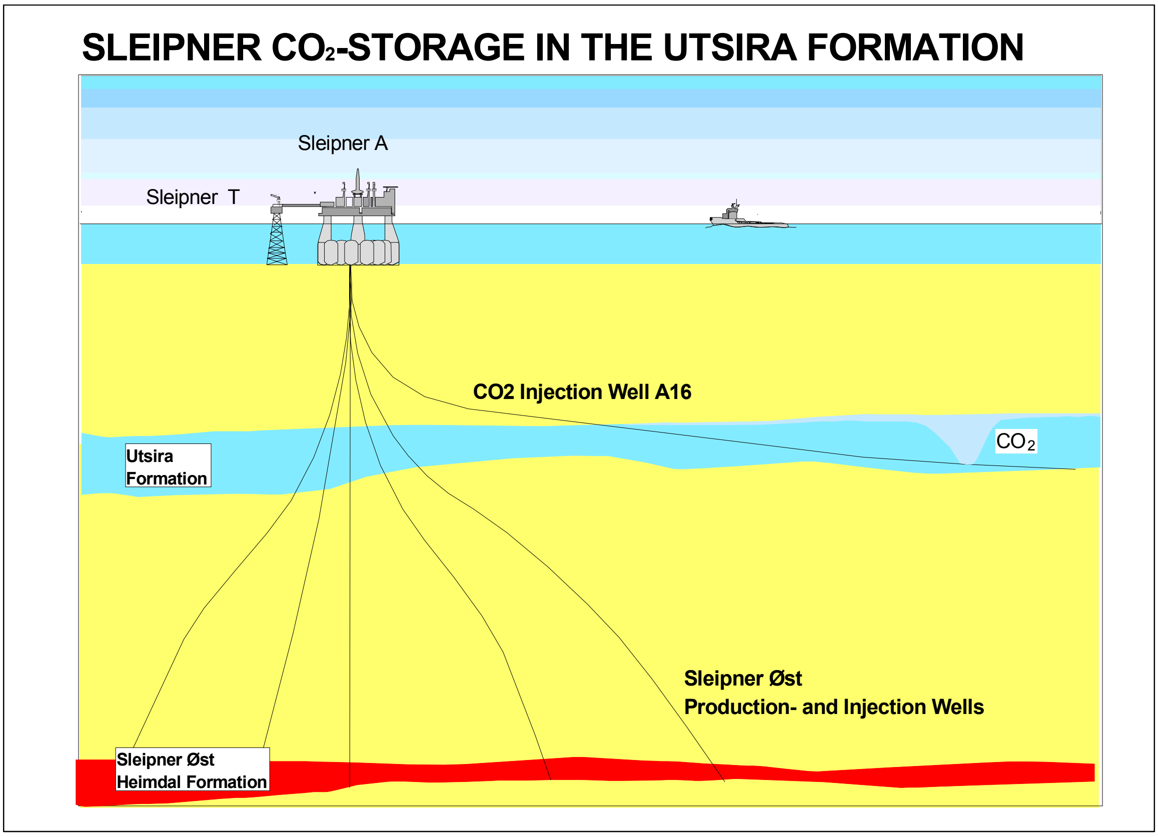

Figure 2. The Sleipner CO_2 injection scheme. About 1 million tons of CO_2 per year has been injected into the Utsira saline aquifer 1000 meters below the sea bottom since October 1996. The Utsira formation is a 200 - 250 meters thick and very permeable sandstone overlaid with mudstone. The CO_2 capture takes place at the Sleipner T (Treatment) platform where it is also compressed. The highly deviated injection well has been drilled from the nearby Sleipner A concrete platform.

The CO_2 capture process that takes place on the Sleipner T platform is based on a standard amine (MDEA) process. The challenge was to make this bulky process compact enough to be fitted on a platform in the middle of the North Sea 250 kilometer from shore.

The SACS Programme

Statoil and the partners in the Sleipner field soon realised that the world viewed the Sleipner CO_2 injection as a full-scale demonstration project for a promising new technology with implications far outside the business of capturing CO_2 from natural gas. In order to learn as much as possible from the injection and at the same time involve a wider group of expertise from many countries, Statoil together with the IEA Greenhouse Gas R&D Programme took the initiative to start the Saline Aquifer CO_2 Storage programme (SACS) for monitoring the Sleipner injection. This 4,5 million US$ R&D programme, run under the European Union R&D Framework programme, involves numerous European geological survey institutions and energy companies in an open process with dozens of papers being published in scientific journals. So far the SACS programme has carried out two seismic surveys in addition to the pre injection survey.

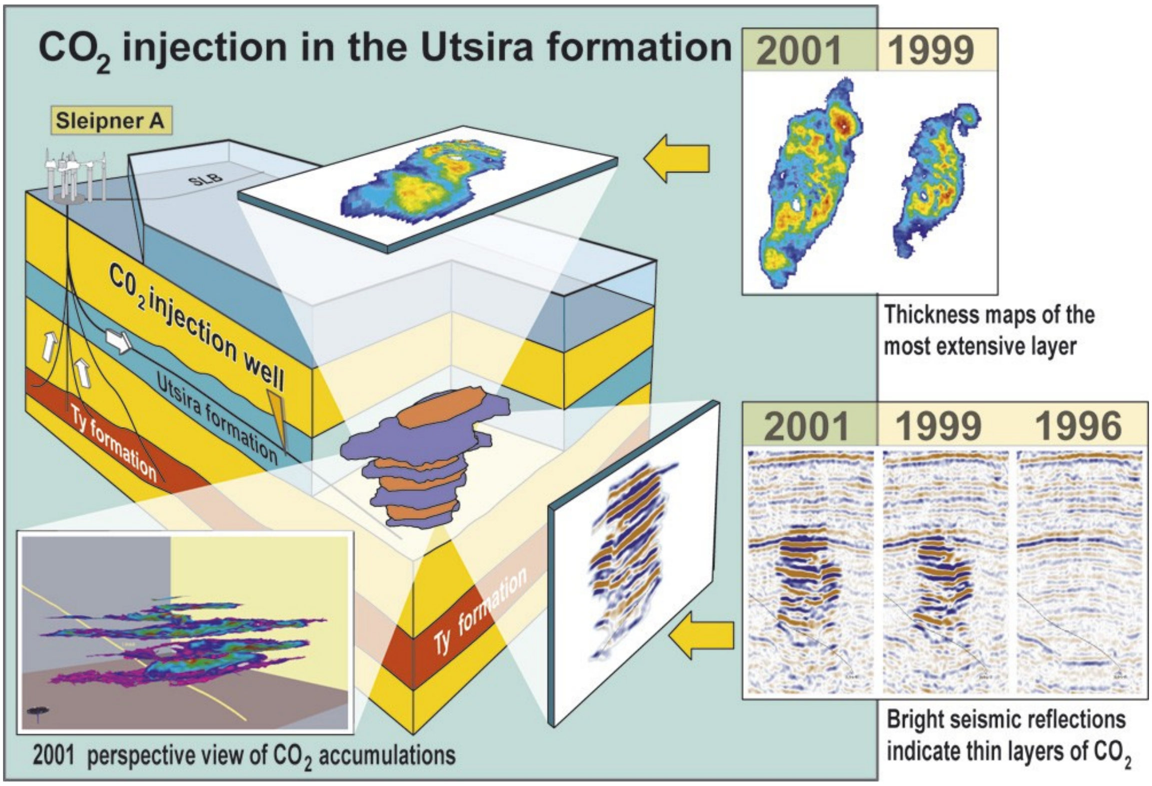

Figure 2. The Sleipner CO_2 injection has been monitored by the SACS programme. This figure shows results from the 1996, 1999 and 2001 seismic surveys (lower right) carried out by this programme. The CO_2 is injected at the bottom of the very porous Utsira formation and progresses up to the mudstone 'roof' above the Utsira formation. From there it spreads out under the roof according to the roof topography (upper right). Due to thin and less permeable layers within the Utsira formation, the CO_2 also spreads out at intervals between the injection point and the roof (lower left). Some CO_2 is already dissolved in the brine

There are plans for continued involvement of the worldwide stakeholders in monitoring the Sleipner CO_2 injection in order to build confidence in underground carbon dioxide storage as a general climate technology.

The Snøhvit CO_2 injection

In the fall of 2001 operator Statoil and license partners in the Snøhvit (name means 'Snow White') natural gas field in the Barents Sea off North Cape in Northern Norway made an investment decision to develop the field. The field, which will come on stream in 2006, consists of a fully sub sea offshore development, a 160 kilometer multiphase pipeline to shore, a liquefaction plant for making LNG for shipment to USA and Continental Europe and - last but not least - a 160 kilometer CO_2 pipeline back to the field to store 0,7 million tons/yr of CO_2 captured from the natural gas during the processing to LNG.

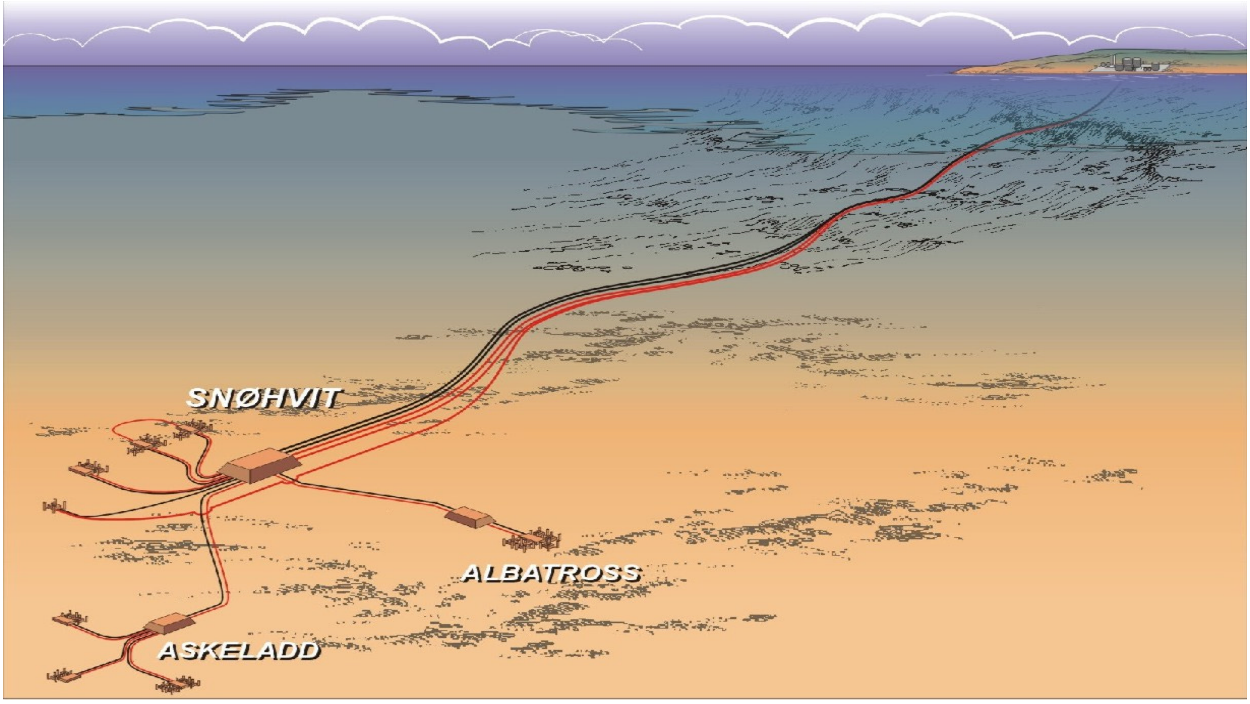

Figure 3. From 2006 about 0,7 million tons of CO_2 per year will be sent back to the Snøhvit field in the Barents Sea from an onshore LNG plant located on the island of Melkøya near the worlds northernmost town Hammerfest (upper right). Unlike the Sleipner injection, CO_2 will in the Snøhvit case be stored below the natural gas reservoir.

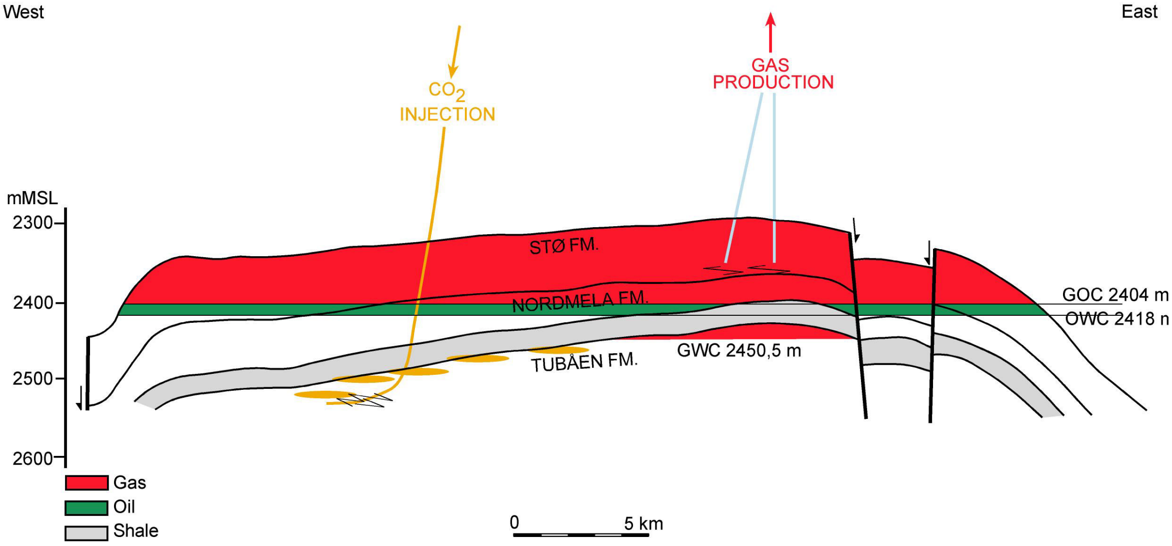

Figure 4. As shown in this figure the CO_2-rich natural gas is produced from the Stø formation at a depth of over 2300 meters. The CO_2 is injected into the underlying Tubåen formation through a dedicated well.

The ‘Vision

About 10 years ago Statoil developed a simplified ‘vision’ of where oil and natural gas may be heading in a climate driven future. This ‘vision’, illustrated in figure 5, shows how fossil fuels - in the figure illustrated by natural gas - can be transformed into the two CO_2 free energy carriers electricity and hydrogen in processes where the carbon dioxide is captured and stored underground. This is an idealised illustration where all the complexities of the real world, especially of the long transition period, have been left out. The usefulness of the ‘vision’ is that it points out a direction for long-term research, development and demonstration, while still being of some help in guiding day-to-day decisions, like the Sleipner and Snohvit injections, having long-term climate implications.

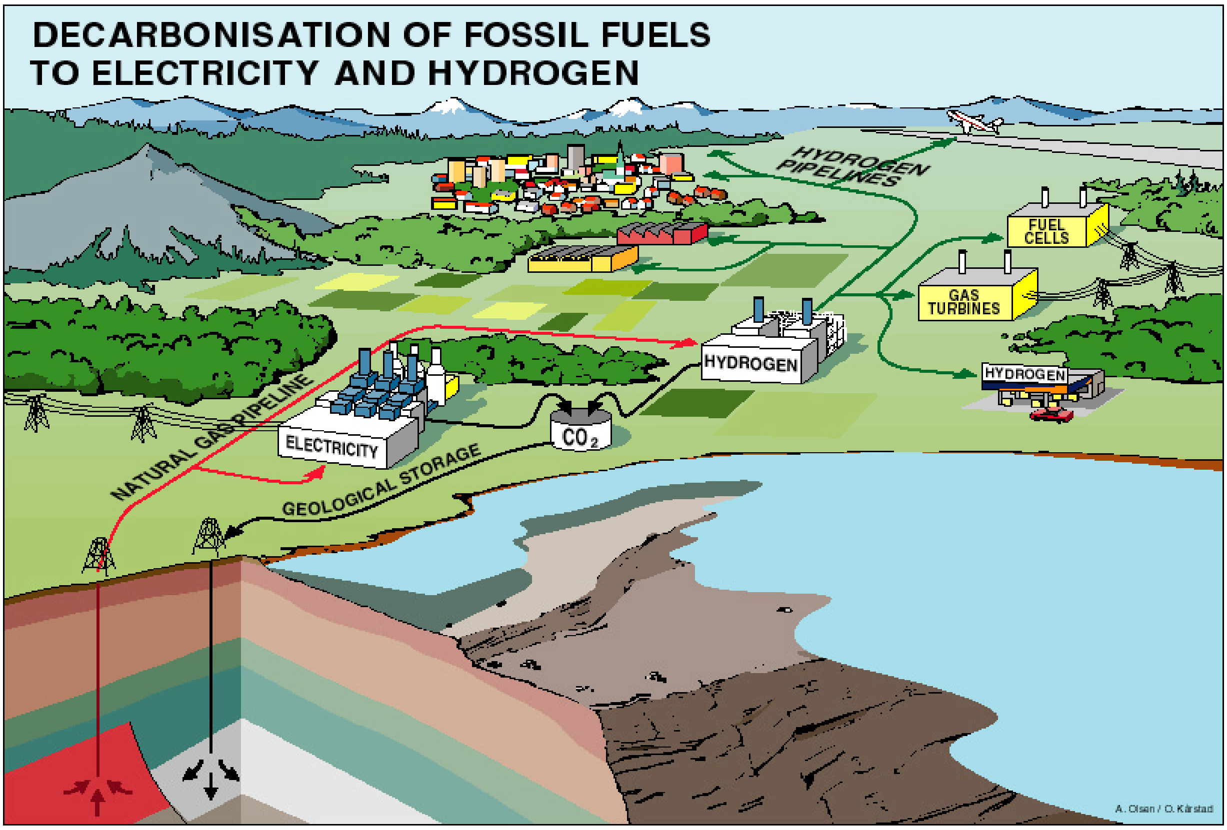

Figure 5. A long term 'vision' of where oil and natural gas may be heading in a climate driven 21st century. The illustration shows how natural gas (or oil, coal) is used to manufacture the two CO_2 free energy carriers electricity and hydrogen. The new element is that processes are incorporated that captures the produced CO_2 and that this carbon dioxide stored long term in an underground formation.

This 'vision' has been instrumental in directing Statoil not only to the two CO_2 injection schemes mentioned above. The capture of CO_2 from various power generation processes, including the hydrogen based route, has been a central R&D topic in Statoil for over a decade.

As a partner in the BP coordinated 'CO_2 Capture Project', Statoil is heading the Norwegian branch of this joint effort to lower the costs of capture.

At the present time, as a follow up of the Snøhvit injection decision, the Norwegian Government and Statoil are discussing the building of an industrial scale demonstration plant for CO_2 capture in connection with gas turbines. Statoil welcomes this opportunity, but the outcome of the discussions are not clear at the time of writing.

The use of CO_2 for enhanced oil recovery (EOR) has been part of Statoil's strategy since the time of the 1990 Sleipner injection decision. The establishment of the first such project in the North Sea has been more difficult than originally envisaged for reasons of timing, volumes or distances. At the time being Statoil and partners are taking a very close look at the Gullfaks North Sea field with the aim of establishing an EOR scheme based on CO_2 from the Kårstø gas terminal.

Notes on the cost of CO_2 capture and storage

The question of investments and operating costs for CO_2 capture and storage can be a quite confusing subject. This is so especially to those who are not involved in such things on a day-to-day basis, but there is always a lot of controversy even within the specialist communities. There are numerous reasons why this is so. Firstly we have to realise that the technologies for CO_2 capture in particular, both novel and those in actual use today, have not been deployed on a really large scale so far. What we see are isolated islands of CO_2 technology, mostly on small and medium industrial scale. The driving force of a large market has simply not been there. Another reason why cost comparisons are difficult is that outside industrial companies there are few common ground rules for how to calculate costs. A third reason is that many of those coming forward with cost figures make their own rules. They may want to promote their own technology, demote someone else's technology or for reasons of their own favour one technology and dislike others. A fourth reason for confusion is that the same technologies come with a different cost in various parts of the world. This difference may be quite substantial. For cost comparison exercises the oil industry often use 'US Gulf Coast' as the least common denominator with respect to siting.

I would like to point to the IEA Greenhouse Gas R&D Programme as an institution that during the last decade have done a lot to establish a level playing field in the area of cost comparisons for new energy technologies. It is my belief that IPCC would do well in selecting the IEA GHG as a favoured source for both cost data and a lot of other information to go into a special report on CO_2 capture and storage.

Below follows some Statoil cost data having to do with CO_2 injection in saline aquifers located under the sea bottom. It should be remembered that these are data for offshore developments where investments in most cases are higher than for land-based developments.

The Sleipner CO_2 injection project can be divided into two large blocks. The smallest investment post can be relatively easily identified, but the other and larger is difficult to disentangle from the large volume of other equipment for natural gas processing collocated with the CO_2 extraction equipment;

a) Investment in CO_2 capture from the natural gas stream:
   No separate investment estimate available, but much larger than b),
b) Investment in CO_2 compression and injection well:
   About 80 million (1996) US $

For the Snøhvit CO_2 injection scheme the situation is basically the same. What we have as identifiable, separate CO_2 items at the moment are estimates for the CO_2 pipeline, well and compressor train. Again we have to recall that this is mostly for an offshore development with the land-based part located in a remote, artic environment.

Table 1 The Snøhvit CO_2 pipeline and -well investment estimates

Invest item	Investment cost Million US$ (2001)
Drilling of offshore CO_2 well	16
Well completion and other well related	9
Pipeline, 8', 160 kilometre	73
Control umbilical (sub sea)	11
Sub sea well frame	12
Sum total	121

In addition to the above investment estimates, there is a compressor train including CO_2 drying with a cost estimate of nearly 70 million US$.

Notes on the risk of CO_2 capture and storage

The relatively easy part is CO_2 capture and -transport. Here it is my belief that the treatment of safety and health issues would do well in tapping into the extensive experience within industry in this area. Should be based on current and prospective standards of safety performance.

The more complicated part is the assessment of risks associated with CO_2 storage. I would like to give the following suggestions:

- Make full use of the experience of oil and natural gas industry with respect to underground storage. Globally there are hundreds of underground natural gas storage sites and a large number of CO_2 injections schemes for enhanced oil recovery.
- Statoil, for our part is fully prepared to contribute all that we know of these matters.
- Efficiency of storage, ecological impacts, and direct risks to safety and environment should be considered separately for underground storage and storage directly in the ocean since they work by unrelated mechanisms.
- Models for CO_2 leakage from underground reservoirs should be based on sound science and facts from experience. Models used in thought experiments common in the literature can lead to very unrealistic conclusions.
- Injection of CO_2 on land may affect groundwater. Learn from government and industry experiences where injection has/has not lead to groundwater effects. Repositories for CO_2 will usually be deeper than most experiences of impacts.
- Operational risk management (including monitoring) should be based, at least in part, on successful relevant experience. This will depend on the setting, geological evaluation, cost, objectives, and the effectiveness of these options.
- Kyoto verification should consider the costs and benefits given the assessment of risks.

Research needs with respect to aquifer storage

A first note is that it may not be of great interest to separate out storage of CO_2 in aquifers from the use of CO_2 for enhanced oil (or natural gas) recovery when it comes to research needs. The tools, the people and the problems are very much the same. A second note is that research is not all that is needed. To progress the knowledge about underground storage of CO_2 with a reasonable speed, we also need to make the most of relevant industry experience and also welcome new underground storage schemes that opens up to research.

Here are a few areas where we consider more research to be especially appropriate:

- Research into less favourable reservoirs than so far studied. Smaller sizes, less permeable, less favourable with respect to fracturing, earth quakes etc.
- Better physical data on CO_2 mixed with a range of other gases such as methane, nitrogen.
- More long term geochemical experiments.
- More, possibly also a broader range of studies of natural (and unnatural) analogues, including experience from oil and natural gas regions globally.
- More work on how storage schemes can leak, likely leakage rates and failure modes, including industry experience and lessons learned from analogues.
- Making the results from such research available to interested parties in an understandable manner.
- Research that can shed more light from various angles on how long CO_2 needs to be stored as well as final fate and likely duration of stored CO_2 under differing storage conditions.

The use of oil, gas and coal fields as CO_2 sinks[6]

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TNO-NITG

The production of carbon dioxide from the combustion of fossil fuels, the resources of which originate from the earth's subsurface, is considered to be one of the prime causes for the recent global warming. The underground structures that contain these hydrocarbon resources do have the potential to act as a CO_2 sink and thus might form a useful link in closing the carbon cycle.

A typical underground CO_2 sink consists of a reservoir that has the capacity to act as a container, and a rock or sediment body that confines the reservoir both in upward direction and in lateral direction. Coals have the special property to adsorb CO_2 and thus immobilise this gas directly.

Once oil and gas fields have been abandoned at the end of the production of hydrocarbons, they might be used for the storage of CO_2. Coal resources that lie too deep to be mined with conventional mining techniques form a third possibility for CO_2 storage in hydrocarbon reservoirs. CO_2 might also help in improving the recovery of hydrocarbons from oil, gas or coal fields thus combining both economic and environmental goals.

A lot of technical expertise is already available for the purpose of underground injection of carbon dioxide, in particular from the oil and gas industry. Injection of CO_2 is common practice in the enhancement of oil production (EOR), especially in the U.S. Natural underground CO_2 reserves are being exploited for industrial application. An underground CO_2 sequestration facility has become a reality with the Norwegian Sleipner project. Demonstration projects of CO_2 injection in coal seams either have been started or are under way in the US, Canada and Poland.

Underground CO_2 injection has a lot in common with underground storage of natural gas (UGS), although there are differences as well:

- CO_2 is denser and more viscous (higher viscosity) than natural gas and thus less mobile,
- CO_2 is not explosive,
- CO_2 is reactive, in particular when dissolved in water,
- The duration of sequestration is longer than it is for storage,
- Much larger CO_2 volumes.

The global potential of underground CO_2 sinks is estimated at 1,000 to 1,800 Gtonnes of CO_2, the amount of which equals to about 50 to 90 years of the present net global annual CO_2 emission by men (various references in Ecofys & TNO, 2002).

Sequestration differs from storage operations in respect of the time window that is encompassed by both applications. Storage activities come to an end as soon as the engineering facilities will be decommissioned (10^1 to 10^2 years). The time frame of sequestration extends well into the period after the abandonment of the site resulting in a lifetime of hundred years or more (10^2 to 10^4 years).

In the next sections we will discuss the status of the various types of hydrocarbon reservoirs as potential CO_2 sinks.

Gas fields

Gas reservoirs are prime candidates for CO_2 storage. They have proven to be effective containers for millions of years. A disused gas field can be used for CO_2 storage if it has not been flooded by formation water. In the latter case storage would in practice amount to aquifer stor-

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[6] The following references have been used in compiling this paper: Van der Meer (2002), Gale (2002), Hendriks et al. (2000), Ecofys & TNO-NITG (2002) and TNO-NITG & ECN (2002).

age. There may be a restriction in the maximum storage pressure to be used, as it is generally accepted that the initial reservoir pressure should not to be exceeded.

The storage potential is considerable; a validated estimate resulted in a potential of more than 30 Gtonnes CO_2 for a representative selection of European gas reservoirs (source: GESTCO). The global potential of gas reservoirs is estimated at about 900 Gtonnes with an uncertainty range between 400 and 2100 Gtonnes (Ecofys & TNO-NITG, 2002).

There are no principle technical barriers for this option although it has not been implemented to date. On the other hand storage of natural gas is routine business in many countries like the US and Germany. Initiatives for demonstration of CO_2 storage in gas fields are being developed in the Netherlands (CRUST).

Improvement of gas recovery (EGR) with the help of CO_2 injection is still in the phase of desk studies. Actually, one of the first reservoir studies on CO_2 storage concerned storage in a gas field. Van den Burgt (1990) investigated the possibilities of enhanced gas recovery (EGR) for a generic Dutch gas reservoir. He found that in this case the CO_2 phase would bypass the natural gas and that for this reason EGR would not work. Recent work by Oldenburg (2000) however, indicates that, for some Californian gas reservoirs, production could be enhanced by EGR. To put this in perspective though, it should be realised that in most cases of primary production from gas fields, recovery could be as high as 95% of gas initially in place, especially if surface-based compression is used. The scope for CO_2 flooding is therefore limited and definitely reservoir specific.

Cost estimates of sequestration in disused gas fields range from 1 to 8 €/tonne CO_2 avoided depending on the depth of the reservoir, re-use of facilities and on- or offshore location (TNO-NITG & Ecofys, 1999; Ecofys & TNO-NITG, 2002). Figure 1 shows the relation between depth and storage costs for reservoirs that are able to store 1 Mtonne of CO_2 per year for 25 years. Offshore costs are substantially higher because of the requirement of a platform. Costs for storage in empty natural gas fields are somewhat lower than for storage in aquifers because of the lower costs for exploration and for monitoring.

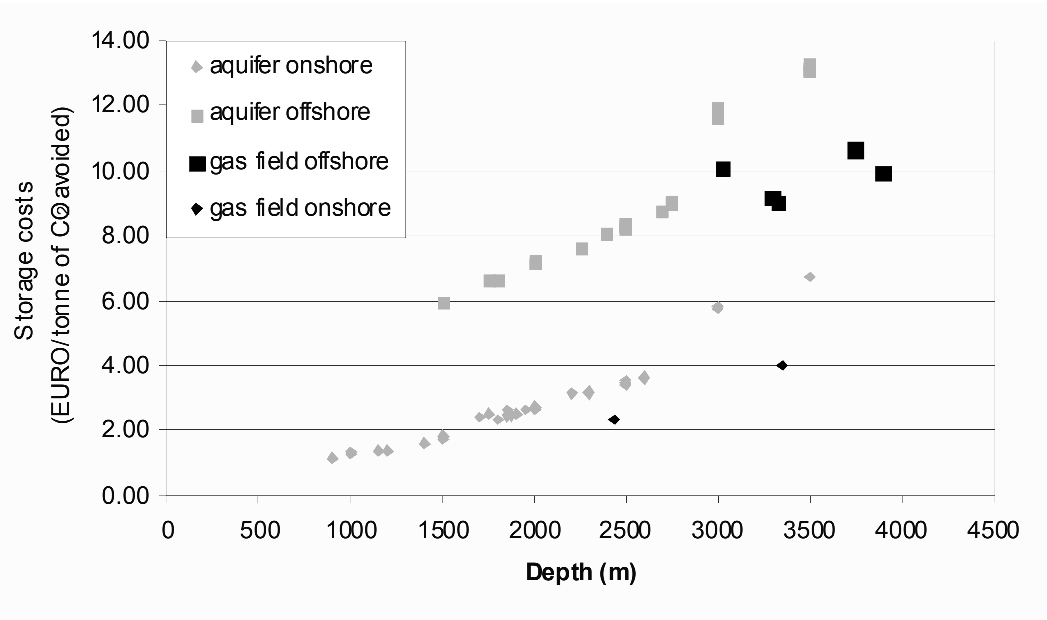

Figure 1. Sequestration costs of CO_2.versus depth for disused gas fields and aquifer traps that are representative for the setting in the Netherlands (TNO-NITG & Ecofys, 1999)

With regard to safety and environmental impact, particular attention should be directed to the integrity of the wells that were drilled for the exploitation of natural gas. They might form locations of unintended CO_2 leakage. Additionally, the reactivity of the seal with fluids containing dissolved CO_2 should be assessed. Starting from the premise that many of the reservoirs have held natural gas for geological time scales, then injected CO_2 has the potential to remain in these structures for similar time scales. Gas reservoirs have been well researched in their development phases.

Oil fields

CO_2 injection is being applied for many years already to enhance the production of oil from oil reservoirs (EOR)*,* in particular in the United States. CO_2 storage is in most cases a by-product of attempts at improving oil recovery (EOR). Since the early days of oil production, ultimate recovery from oil fields has been low, approximately 25% of the oil initially in place, with lows of 5% and highs of 40%. So-called secondary recovery by water injection can be used to stimulate production. As a tertiary recovery process, steam or gas like CO_2 can be injected into the reservoir. The injected CO_2 will improve the mobility of the remaining oil if miscibility can be achieved. Within a certain pressure range, CO_2 is first contact-miscible with oil depending on the type of oil. A further requirement for an EOR project is that the project has to be economically viable. This last point is usually difficult to achieve, because of the high cost of CO_2; including production, purchasing, transport, processing and injecting costs. This is one of the reasons that EOR is far less attractive in Europe.

Once oil fields are economically depleted and abandoned they can be used for the purpose of CO_2 sequestration. Disused oil fields are underpressured or close to the original (hydrostatic) pressure. The process of CO_2 storage in disused oil fields at hydrostatic pressure is comparable to storage in aquifers. The fill up of an underpressured oil reservoir to the original reservoir pressure is more acceptable than overpressuring an aquifer.

The sequestration potential of oil fields in Europe is more modest than the potential of gas fields. About 6 Gtonnes of CO_2 can be stored in a representative selection of European oil fields (source: GESTCO). The global storage potential of oil fields including EOR is estimated at about 240 Gtonnes of CO_2 with an uncertainty ranging from 50 to 1200 Gtonnes (Ecofys & TNO-NITG, 2002).

A lot of theoretical and generic work related to using CO_2 in EOR is available in textbooks and other published literature. Oil companies possess additional practical and site-specific proprietary information. The popularity of this subject is mainly caused by the interest of the oil industry and oil-industry-related service companies. In traditional CO_2 EOR, the main aim is to inject a minimum amount of CO_2 to maximise oil production. Conversely, in the case of CO_2 storage, we try to inject the maximum amount of CO_2 and possibly increase oil production. This difference is demonstrated in the Canadian Weyburn project, which is directed to the co-optimisation of oil production and CO_2 injection. For the owners and the operator of the Weyburn oil field, increased oil production is paramount; while an international consortium is studying the aspects of optimising the net amount of injected CO_2.

The costs of EOR are estimated to range from -10 to 10 €/tonne CO_2 avoided onshore and from -10 to 20 €/tonne CO_2 avoided offshore. Some EOR prospects are already attractive without a subsidy for CO_2 purchase. One must realise that the injection of CO_2 for EOR is less efficient because CO_2 injection is often alternated with water injection (WAG) and part of the injected CO_2 is recycled both resulting in higher costs per net tonne of injected CO_2.

The safety issues that hold for gas fields do also apply to CO_2 sequestration in oil fields. Specific attention should be directed to unintended fracturing of the seal as a consequence of the pressure fluctuations in the reservoir and the gas tightness of the reservoir seal.

Coal fields

In recent years, the use of CO_2 for Enhanced Coal-Bed Methane Recovery (ECBMR, see also Figure 2) has attracted a lot of attention for some obvious reasons. The Earth's sedimentary basins contain an enormous amount of coal. The gas resources within these coals could in principle supply the world with fossil fuel for centuries to come. The global potential for CO_2 sequestration in coals seams is estimated at about 250 Gtonnes with an uncertainty ranging from 0 to 1500 Gtonnes (Ecofys & TNO-NITG, 2002).

The challenge is to unlock the coal-bed methane resources in an economically viable manner. One of the attractive aspects of ECBMR is that for each molecule of gas produced, at least two CO_2 molecules can be absorbed in the coal matrix. One of the main problems associated with developing ECBMR is the low permeability of most unminable coals. This low permeability results in uneconomic production rates. The costs of ECBMR are estimated to range from 0 to 30 € per tonne of avoided CO_2 (various references in Ecofys & TNO-NITG, 2002). The costs can be relatively high because of the large number of wells that are needed in an ECBMR project.

The coal-bed methane industry is most advanced in the United States. In that country, 10 to 20% of natural gas is produced from relatively high-permeability coal deposits. A lot of research in this field has been done by the operators of CBM fields and by coal-mining companies that de-gas coal mines. Some of the results of these research efforts have been presented in dedicated CBM conferences. A breakthrough in the development of ECBMR has been achieved by field pilot studies in the San Juan basin in the U.S. and a pilot test in the Alberta basin (Canada). Unfortunately, however, the results of these projects are not yet available in the public domain because of commercial interests. From restricted information it can be concluded that ECBMR is a promising technique for achieving a higher gas production. A comparable project is being planned in Poland (RECOPOL).

It is obvious that a lot of field testing is needed to gain a full understanding of all processes that are active in a full ECBMR project. These processes include geomechanical, geochemical, multi-gas absorption and adsorption processes as well as processes that affect the flow properties of the coal. In the short term, research priority is to prove that laboratory measurements of these processes are representative of in-situ processes in an ECBMR demonstration project. For instance, it is not clear whether single-gas absorption data obtained in the laboratory can be used to accurately predict multi-component absorption under very different geomechanical conditions.

Compared to other reservoirs, the safety of storage in coal beds is less well understood. In general, the development of this storage technology is behind those of the other reservoirs. Results from the only large CO_2 ECBMR injection trial in the USA has indicated that CO_2 injection has caused swelling of the coal matrix to occur resulting in reduced permeability's around the well area (evaluated on the basis of well tests, Reeves & Schoeling, 2001). However it must be stated that the coal in the San Juan basin has a very high permeability (up to 40 milliDarcy) and seams are thick (10 m). In essence, they represent a unique coal quality that is not typical of the coals available for CO_2 ECBMR throughout the rest of the world. Most coal seams will be thinner (0.5 to 5 m) and have much lower permeability (1-5 milliDarcy) and sometimes will be highly faulted. If swelling occurs in such seams, stresses might be induced on the overlying and underlying rock strata that could cause faulting and possible migration pathways out of the coal seam. Equally, if repeated hydraulic fracturing is necessary to maintain connectivity between the well bore and the permeable areas of the coal seam this in turn could result in over/under burden fracturing (from Gale, 2002).

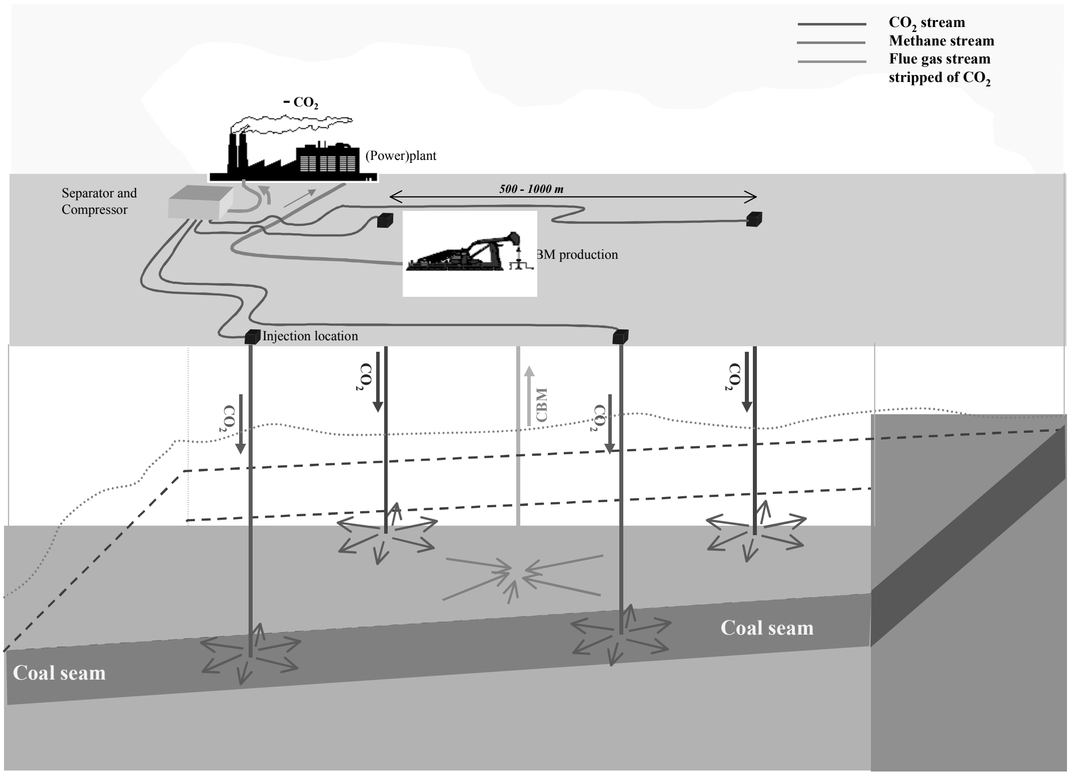

Figure 2. Scheme of an ECBMR facility

Transport

Transport of CO_2 through pipelines is common practice in the US. Transport by truck is more attractive for small quantities of CO_2. Transport by ship is an alternative to offshore pipeline transport, in particular when CO_2 has to be transported over large distances

.Average costs of pipeline transport range from 2 to 6 €/tonne of CO_2 (Ecofys & TNO-NITG, 2002). Carbon dioxide needs to be compressed to 8 MPa before transport. The compression costs amounts to 6 to 10 €/tonne CO_2 (Ecofys & TNO-NITG, 2002). The electricity that is needed for compression determines about half of the compression costs. Figure 3 illustrates the dependency of the transportation costs including compression on the transport distance.

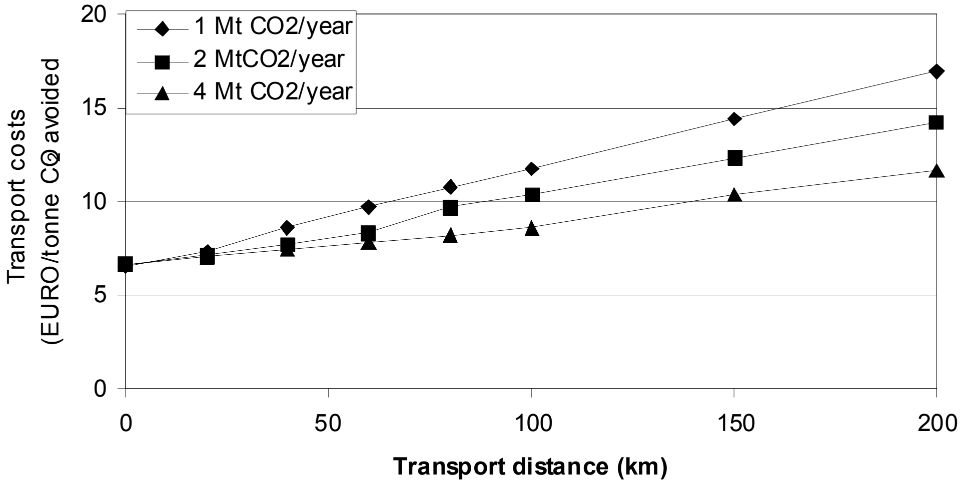

Figure 3. Relation between transport distance and costs of compression and transport

Conclusions and recommendations

In brief it is concluded that (see also Table 1):

- Disused gas fields are the most attractive option for CO_2 sequestration. A safety assessment should be directed to the risks of leaking abandoned wells and seal leakage due to the possible reaction with CO_2.
- Oil fields have potential for Enhanced Oil Recovery, in particular if the price of CO_2 is lowered. The sequestration potential of EOR projects needs to be optimised. A specific risk of EOR is the unintended fracturing of the seal due to the pressure fluctuations in the reservoir.
- CO_2 injection in coal fields to enhance coal-bed methane production is still in the phase of feasibility studies. ECBMR demonstration projects have started or are planned for the near future.
- Transport of CO_2 via pipeline is common practice in the U.S.

*Table 1 Potential of underground hydrocarbon reservoirs for the abatement of CO_2 emission (✱= high; * = low)*

	CO_2 injection in abandoned fields	Improving hydrocarbon production with CO_2 injection
Gas fields	✱	*
Oil fields	*	✱
Coal fields	*	*

We recommend adopting the European/American standards for underground gas storage to the extent that they are applicable to CO_2 sequestration, and expanding the rules so that specific physical and chemical characteristics of carbon dioxide and temporal aspects of sequestration are included. It is further advised to explore the time scales that are specific to the mitigation of CO_2 emission and the related carbon credit system, and to the long-term safety of underground sequestration.

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Ocean storage, including costs and risks

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Abstract

The long-term effectiveness of ocean storage will have to be based on theoretical understanding and models as there is no way to perform experiments on the required time and space scales for outgassing estimation. Based on observations of tracer behavior, the ventilation time of deep water has been revealed. Calibrated and constrained by these results, most of the O-GCMs tell us that CO_2 injected into the thermohaline circulation would not come back to the atmosphere in more than several hundred years.

There are two types of concepts of ocean storage: one is a lake type concept to keep the CO_2 at the ocean floor or a depression site as long as possible, and the other is to inject CO_2 into the deep waters so that it is dispersed as quickly as possible. The technological concepts so far for implementation with minimum environmental impacts are much elaborated based on laboratory and computer experiments incorporating the key understanding of the CO_2 clathrate properties attained in this decade.

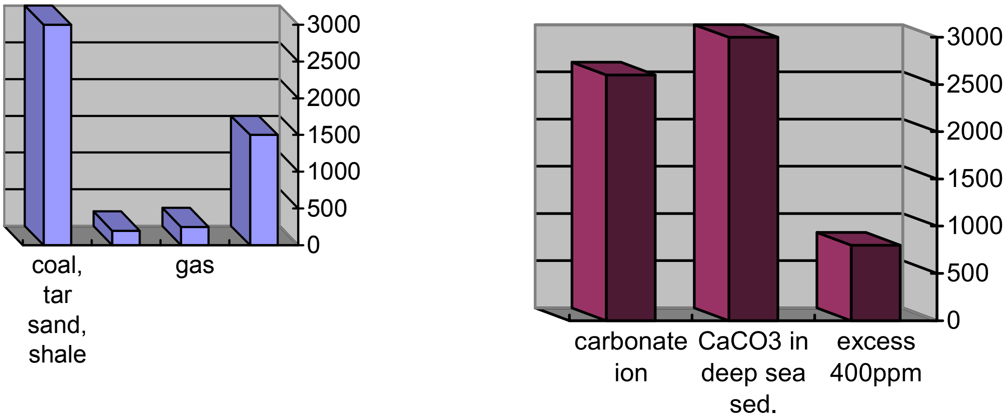
The frequently addressed concern of this technology includes the ecological modification of the ocean system. But even in the business-as-usual release of CO_2 into the atmosphere, some modification might be foreseen in the deep ocean environment and could be inevitable not caused by the climate change but by the direct influence of the increase in the CO_2 concentration in deep waters in future. We cannot stop the CO_2 invasion into the deep ocean due to the existing of the excess CO_2 in the atmosphere. Whichever release method is used, carbon dioxide we are releasing to the atmosphere now will find its way into the deep oceans. Hence, the right scientific question is whether there exist additional risks to the deep-sea environment associated with this technology. If we accept the target of a stabilization level of the atmospheric concentration of CO_2, our generation's commitment to the CO_2 futures anyway extends to the modification of the deep-sea environment induced by the increase in atmospheric CO_2 concentration level.

The environmental impact of the injected CO_2 in near field is manageable, in principle. The field experiment will offer the opportunity to increase and validate our ability to the environmental impact assessment of this technology.

Introduction

In order to understand the future climate for centuries ahead, we need knowledge on CO_2 behavior in the atmosphere, the ocean and the terrestrial biosphere on timescales of years to tens of thousand years. Based on the same knowledge, we can control the CO_2 concentration of the atmosphere by the engineering approach (Marchetti, 1977) for managing the CO_2 emission. The technology of ocean storage of CO_2 offers the means of ‘peak-shaving’ the time profile of the atmospheric CO_2 concentration before its reaches the long-term equilibrium level (Hoffert et al., 1979). The knowledge of the carbon cycle (Wigley and Schimel, 2000) offers the basis of this future projection of the atmospheric CO_2 concentration.

Figure 1 illustrates the potential carbon sources and sinks compared with the estimates of sizes of the ultimate minable reserve of carbonaceous fossil fuels. With the carbonate alkalinity of seawater to be constant, the increase in CO_2 causes a decrease in $[CO_3^{2-}]$ in seawater. Hence, the bar for the carbonate ion in the Figure shows the primary capacity of the oceanic sink for the purposeful storage of CO_2. The CO_2 ocean storage is thus to be examined in the context of a fossil fuel era (Khesghi, 2002). On the other hand, in the context of CO_2 inventory, one can easily understand that the purposeful injection of CO_2 into the ocean now means a decrease of the future sink capacity of the ocean when a part of the injected CO_2 reached surface waters, in a few centuries later from the present.



The unit is Giga tons Carbon
The last bar shows the amount of extra CO_2 required to raise its content in the atmosphere by 400 ppm.
Source: Broecker (2001)

Figure 1 Potential carbon source and sinks

Compared with the amount of the fossil fuel reserves, the physical ocean capacity is almost infinite, as we will see it later in the discussion on the lake scenario of the storage concept. Figure 2 is an example of the explanation on how large the oceanic capacity is even in the dilution scenario of the ocean injection. The shift of concentration profile of total inorganic carbon contents of the seawater is calculated and added to the observed profiles in the North Pacific and the North Atlantic Oceans, provided that the injected CO_2 is uniformly distributed within the water columns from 1 km depth to 3 km.

The question of when this decrease will be effected or the question on the 'sequestration efficiency' can be examined by the O-GCM model prediction (Orr, 2000). There is little consensus at present particularly about the overall viability of direct injection into the mid-depth range among the efficiency estimation results by three-dimensional ocean models. We infer that the cause of the inconsistency is due to the lack of understanding in ventilation process of the ocean in mid-depth ranges (500-1750m) (Broecker, 2001), or more specifically in the process associated with the Southern Ocean (Mignone et al., 2002).

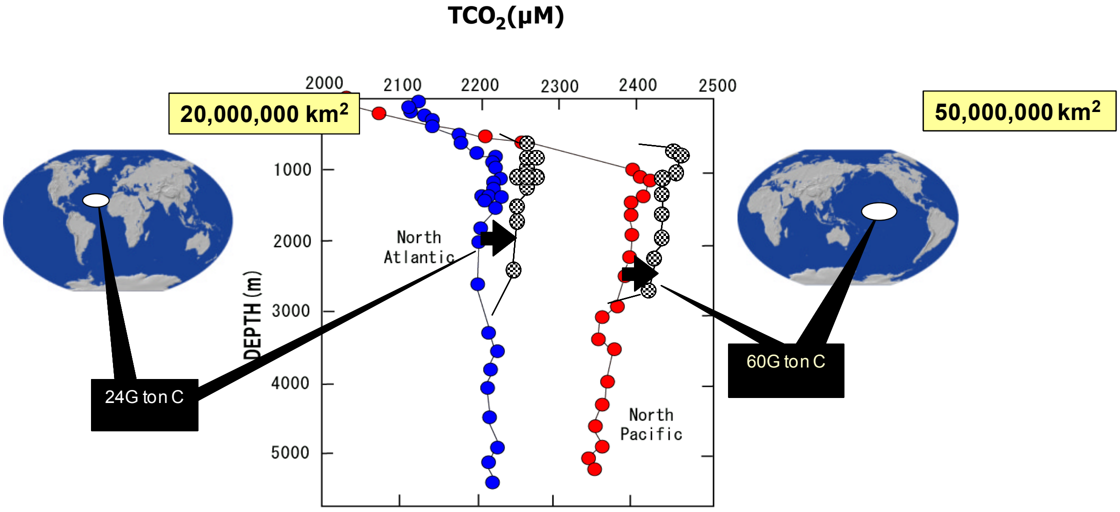


Figure 2 An example of the storage capacity of ocean storage

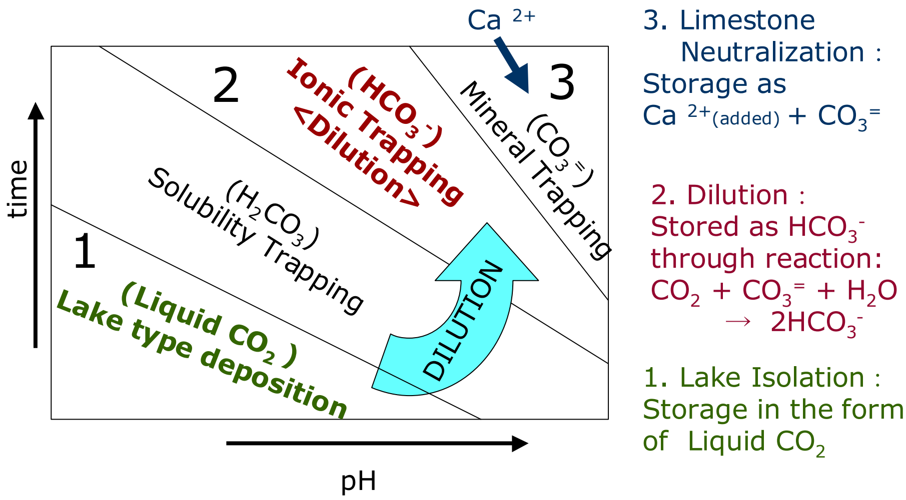


Figure 3. Trapping mechanism of ocean storage schemes as compared with geological options: 1; Lake isolation strategy, 2; Dilution/dispersion strategy, and 3; Neutralization with added limestone

Recently, a third way of ocean storage has been proposed (Caldeira and Rau, 2000). The three types clearly differ in the trapping mechanism of CO_2 in the ocean. As illustrated in Figure 3 for comparison with geological storage options, the pH impact to the ambient environment decreases in this sequence.

Technologies

From the first proposal of this technology (Marchetti, 1977) twenty five years ago to the present day detailed technical examinations, the method of CO_2 injection into the ocean is discussed in both directions: the isolation from water body i.e. typically 'lake scenario' to limit the spatial extent of the impact, and the dispersion/dilution in water body to minimize the degree of impact. For example, the dry-ice (solid CO_2) dropping method which is the simplest but energy intensive and costly implementation of this technology, and was proposed (Steinberg, 1985) and then examined (Nakashiki et al.,1991) in the early days of research work, could be implemented to the either directions by selecting simply the size of dry-ice blocks: a solid CO_2 cube with 3 m inside length would lose half of its initial mass to dissolution at a depth of 3000 m, where the melted liquid CO_2 with the same temperature as of the ambient seawater becomes heavier than the seawater.

Several years ago, a review (Ohsumi, 1995) was made of a wide range of technological studies on the implementation of both concepts of isolation and dispersion. Following this review, there also appear several technological concepts for the implementation of CO_2 ocean storage, most of which eventually aim to minimize the overall environmental impact.

Table 1 Technological Schemes of CO_2 Ocean Storage

Dilution/dispersion strategy:
+ longitudinal dispersion (Ozaki et al., 2001; Tsushima et al., 2002)
+ ascending plume (Crounse et al.,2001; Chen et al., 2001)
+ descending plume (Wannamaker and Adams, 2002; Nihous, 2002)
    - by hydrate particles (Takano et al., 2002)
    - by droplets containing hydrate (Hirai et al., 1999)
+ isopycnal spreading (Golomb, 2002)

Lake isolation strategy:
+ depositing with vertical short pipe in cooled liquid containing solid (Aya et al., 2002)
Release of calcium and bicarbonate ion to the sea near to the emission site of flue gas (capture and storage combined) (Caldeira and Rau, 2000)

Besides the direct injection of liquid CO_2 or its hydrate to the ocean interior, the novel concept, i.e. the last item in the listing of the Table, was proposed recently to the ocean sequestration strategy; the release of bicarbonate ion resulted by the limestone/water/flue gas reaction at the emission site. Since the neutralization of the CO_2 with calcium carbonate is the geochemical consequence in the ocean environment in time scales of several tens thousand years, the essential feature of this proposal is to avoid the decrease in the oceanic sink that is expected a few centuries after injection.

As seen in the above table summarizing these proposals, a part of this progress is backed by the continued laboratory works or the computer experiments. The research using remotely operated vehicles (ROVs) or submersibles (Shitashima, 1997; Brewer et al., 2002) is also very fruitful, because all the conditions we encounter in deep sea are neither fully understood nor simulated in land-based experiments. Even laser Raman spectroscopy is being used in situ (Brewer et al.,2002).

Lake scenario

The main advantage of 'lake scenario' over the dilution scheme is an additional retardation of CO_2 to reach the surface. The performance (i.e., leakage rate) estimate of the lake-type deposition of CO_2 onto the ocean floor and the topics of CO_2 hydrate properties in relevance to this concept were covered in the previous review paper (Ohsumi, 1995). The recent model study (Fer and Haugan, 2002) shows that the leakage rate of CO_2 as solute into the ambient bottom waters is equivalent to 0.1 m/y expressed as the surface retreat rate of the liquid CO_2 lake, which is one order of magnitude larger than the figure the former estimate (Ohsumi, 1995). As seen in the study on the 'lake type scenario' (Nakashiki, 1997), more research on the actual ocean floor flow regime is needed to estimate the dissolution of such a pool of liquid CO_2 on the ocean floor. In conclusion, this concept was poorly documented in a systematic manner, partly because the nature of the benthic boundary layers and benthic storm phenomena are not well understood.

Plume dynamics study

The ocean has the natural structure of density stratification and the fact that CO_2 hydrate has a greater density than the CO_2 enriched seawater makes it necessary for the modification of a simple plume model. Ascending and descending plume behaviors are modeled so far (Sato and Sato, 2002; Wannamaker and Adams, 2002) and, more importantly, the international project on the ocean field experiment of CO_2 injection into the sea provided the participating modelers from various research institutions the opportunity to undertake the inter-laboratory comparison of their models. The collaboration among the modelers were very effective to make feedbacks to the laboratory physical property studies resulting in the promoted effort of more critical laboratory measurements. The study will provide the basis for the formulation of the efficient scheme of the injection with reduction of the environmental impacts.

Study on phase property

The laboratory studies using a small scale experimental set-up (e.g., Uchida, 1997; Warzinski and Holder, 1999; Yamasaki et al., 1999; Yamane et al., 1999; Uchida et al., 1999) revealed almost all of the important questions in formulating the plume dynamics. The laboratory experiment using high pressure test facilities provided the progress in understanding the processes at the surface of the CO_2 droplet where the CO_2 hydrate membrane occasionally covers and affects the transport phenomena at this interface. The comprehensive study of both concepts of fixed point release of CO_2 and CO_2 lake scenario was conducted in Tokyo Institute of Technology (Hirai et al., 1997a; Hirai et al.,1997b; Hirai et al., 1997c), where the transport property of liquid CO_2 under deep ocean conditions were collected using high pressure apparatus of the appropriate size for such work. Using a larger high pressure tank was also effective and the prediction of ascending phenomena of an independent single droplet of injected CO_2 in deep ocean environment becomes reliable (Ozaki et al., 2001).

Transport

Having identified the CO_2 emission sources, it is then necessary to match these sources with geological reservoirs and/or suitable sites in the ocean. This mapping, on a regional basis, of ocean storage opportunities is not underway. In GOSAC project (Orr, 2001), the following seven sites are selected based on the accessibility to the deep ocean from large emission sources:

Bay of Biscay, off New York, off Tokyo, off San Francisco, off Bombay, off Rio de Janeiro, and off Jakarta. That was the only example to show what one should bear in mind when we consider the problem of transport.

Although the problem the deep-water pipelines even to a depth of 3000 m is tractable according to experts (Palmer, 1997), it is reasonable to conclude that the longer the transport distance, the more economical ship transport becomes. Ship transport was extensively examined in Japan (Ishimaru, 1997).

Costs

In 1996, the cost analysis on ship transport including injection was presented by Mitsubishi Heavy Industry (Fujioka et al., 1997). Pipeline deployment in the US for ocean injection also appeared in the literature (Halmann and Steinberg, 1999). The cost, in general, is comparable with generic estimates in geological storage. Considering the economy of scale, the cost estimate is usually conducted on the several units of a typically 1000MWe – scale fossil fuel fired power plant.

Research on technology described in the previous sections in this paper was targeted at more reliable prediction of the impact in a near field or alternatively they are the challenge for developing of a reasonably attainable dilution method. Therefore, the results of these efforts will not drastically change the economics of ocean storage.

There must be many detailed cost analyses not open to public on the various options of CO_2 injection. The author believes that these efforts show roughly that we need not to pay more than 10USD per ton CO_2 when liquified or pressurized CO_2 is available at the oceanic coast.

Future R&D for the technology

The level of integration as a whole system is the most advanced in the case of ‘moving ship’ concept (Ozaki et al., 2001) featuring the minimum attainable impact to the immediate ambient water mass at mid-depth range in the ocean, but this example is an only comprehensive feasibility study.

For the industrial background of the actual technology, we have the experience in handling large volumes of CO_2 in the oil industry such as in EOR practices. When the CO_2 behavior in the ocean is well understood in a controllable manner, particularly for any injection method, and the corresponding environmental assessment is established through the elucidation of the phenomena under actual ocean conditions, the lead time of technology development for full scale implementation, such as 100kg CO_2 per second injection rate, is considered to be several years.

Before the R&D for full scale implementation is conducted, the performance of each proposed technology should be tested in the actual ocean on an appropriate scale, particularly for the purpose of establishing environmental assessment methods associated with the technology. In relation to the risks to be discussed below, appropriate risk management systems should be developed in the course of R&D. We are now going to this stage, and therefore the success to make the ocean experiment planned in the International Collaboration on Ocean Sequestration is critical.

A larger scale field experiment (Haugan, 1998) might be also necessary in the development of the technology and should be conducted under international collaboration

Risks

Risk is not treated so far with regard to the future implementation of the technology. Specific risks associated with the implementation of this technology should be scrutinized in the context of our recent history towards the preservation of the ocean environment, i.e. the provisions of the London Dumping Convention and others. The principle discussed in the forum of these international conventions on the ocean environment is that waste originating from land-based human activities should not be transferred to the ocean. However, the CO_2 emitted from human activities already finds its way to the ocean. Therefore, if we make a short-circuit route for CO_2

to the deep ocean by skipping its existing path through the atmosphere and surface ocean, the question is whether there exist the additional risks to the deep ocean environment. The key issue is the unintended consequences. This could lead to an assessment of the environmental vulnerability of the deep ocean compared to the other parts of the environment that are exposed directly to future increase in greenhouse gases.

The risks in the geological long-term were identified as the enhancement of the carbonate sediment dissolution rate. Consequences include destabilization of the continental slope that could cause deep-sea avalanches. This type of geological hazard is difficult to quantify and might not be an additional risk to the business-as-usual emission scenario.

The biological risks are being discussed in more detail and for the long-term ecological risks, in particular, we reached provisional conclusions. In the second workshop organized by IEA Greenhouse Gas R&D programme, the suggestion of four principles on which the management of CO_2 emissions should be based was made. These were:-

- No species should be driven to extinction.
- There must be no significant disruption of ecological processes at basin-scales.
- There should be no increased impact on living resources over and above that which will occur if no mitigation is exercised.
- + Limits must be set to the volumes of oceanic waters and areas of sea-bed within which critical changes in pH and/or CO_2 concentrations are permissible.

It is to be noted that these guidelines came from the definition of ‘pollution’ adopted in the London Convention and the principles as follows (Angel, 1997):

- Development must be in a manner that avoids prejudicing environmental amenities for future generations.
- Serious and irreversible damage to the environment must be avoided.
- Measures which transfer damage from one environmental compartment to another must be avoided.
- There is a need for concerted international action to achieve environmental protection and preservation.

These principles were also those we have based ourselves on the United Nations Framework Convention on Climate Change (UNFCCC), hence the problem here is the concept of ‘pollution’ with relation to the risks associated with ocean storage of CO_2.

The above discussion resulted in the guidelines was made in early 1996 and the needs for the biological studies were documented for the first time in accordance with the former discussion on the protection of marine environment on this occasion, by taking into account that if business-as-usual emissions of CO_2 continues, the consequences for global systems, mainly via climatic effects, would be unacceptable under the same criteria.

Recently, new findings on the possible direct, not ‘via climate’, effect of CO_2 on marine organism were reported (Angel, 1997). It suggests that the CO_2 partial pressure increase in surface oceans with an increment of 200 micro atmospheres could significantly affect the growth rate of some sea urchins. The inferred mechanism is that the induced decrease in $[CO_3^{2-}]$ concentration causes a decrease in the solubility products $[Ca^{2+}][CO_3^{2-}]$, and consequently the organisms need more energy to maintain formation of their carbonate skeleton. Considering that these effects on marine organisms will be exerted directly to the surface fertile domain of the ocean, the revealed facts may lead to a discussion of the optimum redistribution of unequilibrated excess CO_2 between deep oceanic interior and surface ocean environment (+atmosphere) in a protective sense of ocean environment as a whole. The similar discussion (Thornton and Shirayama, 2001) in this course was also presented in terms of pH change in 1995, so the findings are more straight-forward evidence we should take into account when considering the risks associated with the technology on the marine environment.

Short term local impact

Lethal direct impacts of CO_2 to biota are well documented by the effort of the Japanese R&D program from 1997 to 2002. For example, onboard experiment of lethal effects of CO_2 to deep-sea plankton (Watanabe et al., 2002) gave those important inputs to the assessment models such as developed by the MIT group (Auerbach et al., 1997). Hence, the provisional impact assessment can be ready to present,. if site specific data on an ecological structure for the deep sea environment is available.

Conclusions

1) Where the opportunity for geological storage is restricted for geographical or geological reasons, ocean storage could be a major constituent in the mitigation policy package.
2) Before starting the actual technology development for implementation, the knowledge of the CO_2 behavior in the near field region of injection should be confirmed or verified in the actual ocean, trough experiments
3) The ecosystem impact needs to be revealed in more detail for the requirement posed in the context of the assessment of technology relating to the ocean.
4) The site specificity is the key for the implementation of the ‘lake type’ storage. In this case, detailed ocean surveys including baseline studies are very necessary.
5) The geographical proximity of ocean and geological storage to sources differs. The intrinsic advantage of ocean storage over geological storage is the relative flexibility in the site selection. Furthermore, the generic assessment methodology of ocean storage may be modified to an actual implementation case more easily than in the case of geological storage.

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General overview of costs

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Abstract

The cost of capture and storage of CO_2 can be understood as built up from 3 distinct components: the cost of capturing CO_2, the cost of transmission and the cost of storage. By convention, the IEA Greenhouse Gas R&D Programme incorporates the cost of compression in the cost of capture; this approach will be followed here.

The cost of capture tends to be the dominant item for current technology; results from the IEA Greenhouse Gas R & D Programme and other sources will be discussed. The cost of transmission is a function of the amount of CO_2 being shipped and the distance - some examples of this will be provided. The cost of storage is a function of capacity, which varies from country to country and between types of storage reservoir. Data collected by the IEA Greenhouse Gas R&D Programme for storage capacity and cost will be illustrated.

Having assembled capital and operating costs in a suitable framework, it is then necessary to relate these to emission abatement. The concept of 'emissions-avoided' will be introduced as a representative measure. Some of the problems encountered in using this measure will be described. These factors are finally brought together in a discounted cash flow calculation – the assumptions used for this can have a major impact on the results, and on their comparability with equivalent calculations for other mitigation options. The cost of avoiding CO_2 emissions will be presented for several capture and storage options.

Introduction

This paper is intended to provide an overview of the costs of the technology of capture and storage of CO_2. This technology has recently been attracting an increasing amount of interest for a number of reasons, not least of which is that it can be implemented by combination of known technologies developed for other, if related, purposes. The corollary of this is that the cost of the technology can be relatively accurately predicted by standard chemical engineering procedures. Thus much of the data quoted here, especially on capture and transmission, has been obtained from the cost estimating departments of engineering contractors. Such studies can produce estimates of relatively high confidence (+/- 25%) without large effort. Further refinement of the accuracy can be obtained in return for greater effort. However, for the purposes of assessing the option of using this technology for abatement of CO_2 emissions, this degree of accuracy is quite sufficient.

There are various types of study from which this data can be obtained. Several organisations have commissioned engineering studies (especially of CO_2 capture and transmission) from professional engineering companies – examples of these include the work of the IEA Greenhouse Gas R&D Programme (IEA GHG), US Department of Energy (DOE), EPRI, CO_2 Capture Project, etc. In some cases, the results of these studies are in the public domain or have been summarised for dissemination in the technical community (e.g. Davison et al, 2001, Booras and Smelser, 1991, Simbek, 1999) although, often, there is some restriction on publication of the full results.

A second class of study makes use of the first type, re-working the results into a comparable set so that they can be more easily compared. Examples include Goettlicher and Pruschek, 1999, Herzog, 1999 and Hendriks, 1994.

A third type of study develops parametric analysis from the first 2 types and their sources or by use of chemical engineering software, to examine the effects of different plant configurations and other matters on overall cost; examples include David and Herzog, 2001 and Rubin and Rao, 2002.

Costing of CO_2 storage tends to be more site-specific and less open to generalisation. As far as is possible, this paper will draw on results of the engineering cost analyses, with examples of storage costs from a range of sources. CO_2 utilisation is considered in the discussion here about CO_2 storage but other uses of CO_2 (e.g. to make products) are not considered here since none have been identified which would produce net emissions reduction at a scale sufficient to make useful reductions in anthropogenic emissions Audus and Oonk, 1999.

The cost of capturing CO_2, the cost of transmission and the cost of storage will be examined separately. These costs will then be related to the amount of emissions abated and at what time – the methods and assumptions for doing this will be examined. The results will be presented for several capture and storage options. Finally, possible cost reductions in future will be discussed.

Components of the cost of capture and storage

Capture of CO_2

Criteria for technical assessment
It is essential in any cost estimate to establish criteria for the assessment. Defining these as precisely as possible will provide the highest degree of confidence in the results and help in comparing one option with another. However, defining the criteria very tightly may mean that the results are not readily translatable into other circumstances and certainly makes for difficulty in comparing the results with other assessments done using different criteria.

In an assessment of a power plant with/without CO_2 capture, criteria which must typically be defined include:

- Fuel composition and cost
- Ambient temperature, including cooling water temperature.
- Fraction of CO_2 to be captured
- CO_2 purity and export pressure
- Plant size, duty and load factor
- Project lifetime and construction period
- Economic factors (these will be discussed later)

Fuel composition depends to some extent on the location of the plant, as do ambient conditions; for these reasons, the IEA Greenhouse Gas R&D Programme (IEA GHG) has established a set of standard assessment conditions to enable comparison of different options. A key parameter is the cost of fuel – although this may well be treated as a variable, it is often necessary to select single values for quoting costs of particular mitigation options. In IEA GHG's studies, the cost of gas was assumed to be \$2/GJ and the cost of coal \$1.5/GJ.

The degree of CO_2 capture is an issue usually dealt with by engineering judgement – typically 85% or sometimes 90% of the CO_2 in the flue gas would be captured. The degree of capture will affect the cost and energy penalties, especially in a gas-fired combined cycle system, where the CO_2 content is much lower than in a coal-fired cycle.

Another aspect which has an important influence on the cost and performance of a plant is the nominal rating; IEA GHG has standardised on 500MWe, on base-load operation, both with and without capture. By using the same plant rating with and without capture the effects of capture on plant efficiency and output are automatically allowed for. IEA GHG's assessment of a power plant with capture also includes the cost of compression of the CO_2 to the delivery pressure (which is standardised at 110 bar in IEA GHG calculations).

The operating cost is usually dominated by the cost of fuel, so a key parameter is the thermal efficiency of the plant; other significant contributions are cost of labour, maintenance, purchase of chemicals and other consumables and, in the case of solvent scrubbing plant, the cost of solvent for make-up purposes. Another key influence on cost of generation is the capital charge - a useful measure of capital cost is the specific capital cost of the plant (i.e. the capital cost divided by the power output). Other factors which may or may not be included in an evaluation include allowance for funds used during construction, working capital, commissioning, taxation, insurance and fees

The main types of plant with capture which will be discussed here are post-combustion and pre-combustion removal of CO_2, using either coal or natural gas as fuel. These could be built today based on known technology, hence giving confidence in the cost estimates.

Post-combustion removal - coal fired plant

The pulverized coal-fired plant is currently the main method of using coal for power generation. CO_2 would be captured from the flue gas stream (i.e. post combustion using a solvent such as MEA). Choice of steam conditions has a significant effect on overall efficiency - changing from sub-critical steam (say 170 bar, 535˚C with single reheat) to ultra-supercritical (USC) at say 345 bar, 649˚C, with double re-heat, can add 4% points to efficiency. Thus use of the higher efficiency plant would be consistent with designing a plant for reduced greenhouse gas emissions.

About a third of the penalty for CO_2 capture is due to auxiliary power consumptions, such as for the flue gas fan and the CO_2 compressor – the rest is due to the steam consumed for amine regeneration.

Addition of CO_2 capture to a plant design increases specific cost because of the cost of the CO_2 scrubber and its ancillaries and also because of the reduction in power output due to the energy losses in capture and compression. Thus, in order to achieve the nominal rated output, the plant will have to be built larger in some respects, so as to compensate for the losses incurred by CO_2 removal. In pulverised coal plant, about half of the increase in specific capital cost is due to the cost of the CO_2 capture equipment and half is a result of reductions in the power output.

Post-combustion removal – gas plant

The plant is based on natural gas combined cycle; MEA is used for scrubbing the flue gas stream. Here there is more scope for variation in plant design because of the range of gas turbines available. Some analyses have been conducted using current F-class gas turbines; others looked at gas turbines which are in the process of being qualified for use, such as the H-class gas turbines. F-class turbines have inlet temperatures of 1260-1370˚C and air cooling of the blades - most of the large natural gas combined cycle plants being built in the world today use this type of turbine. H-class gas turbines have a higher inlet temperature, about 1430˚C, and steam cooling of the first row of blades; they are only now coming into use.

Because of the large unit size of these gas turbines, it is not so easy to match a pre-determined plant rating, such as the 500MW used by IEA GHG. It may be necessary to assume a different size and adjust the costs according to engineering sizing rules. The specification of either 50Hz or 60Hz operation will also affect this (the power output of a 60Hz gas turbine is about ⅔ that of the corresponding 50Hz turbine).

It should also be noted that gas turbine prices are very sensitive to market conditions. In recent years, gas turbine prices have fluctuated due to large changes in supply and demand.

Pre-combustion removal – coal plant

In precombustion decarbonisation, a fossil fuel is converted into an intermediate (low carbon content or carbon-free) fuel such as hydrogen or a hydrogen-rich gas mixture. Removal of CO_2 is carried out in a reducing atmosphere, which is better suited for amine scrubbing. The Integrated Gasification Combined Cycle (IGCC) is an example of the type of plant in which this concept would be applied. The IGCC approach is only now becoming commercial, which means there are many more variants in design than in the PF plant. Consequently there are greater differences in analysis of the cost and performance of IGCC plant with CO_2 capture. Some of the aspects of the design which can be varied include:

- Gasifier – dry feed or slurry feed, which affects efficiency, type of syngas produced, suitability for CO_2 removal, capital cost, etc.
- Gasifier pressure.
- Syngas clean-up – in some studies, the same method is used both with and without capture; in others, different methods are used.
- Shift reactor and CO_2 removal.

- Gas turbine – similar issues as described above, plus the question of ability to burn hydrogen rich fuel.

Many of these variants are based on known technology but in some cases the technology has not yet been demonstrated in the particular application (e.g. high pressure, slurry-fed gasifier). CO_2 capture is best done using physical solvent.

This range of variables for the design leads to a much greater range of specific costs for IGCC plants than for PF plants in published studies, and hence to greater range in the penalty for capture.

Pre-combustion removal – gas plant
This is a concept which has been receiving increasing attention in recent years [Audus et al, 1999, Freund and Haines, 2002] as an alternative approach to capturing CO_2. The costs of this method have been assessed by the IEA Greenhouse Gas R&D Programme, Norsk Hydro and others. For natural gas, fuel processing is by partial oxidation or by steam reforming rather than gasification as done for coal. Because combustion air has not been introduced at the point where the CO_2 is separated, the gas volumes are much less than in post-combustion removal, which is particularly advantageous for capturing CO_2 in natural-gas-fired plant.

Discussion of costs
The capital costs of various studies of power plant with and without CO_2 capture are shown in Tables 1 and 2. The data are from IEA Greenhouse Gas R & D Programme studies and from EPRI studies; some data from David and Herzog [David and Herzog, 2001] are also shown – they analysed a number of studies to put them on a consistent basis. The IEA GHG and EPRI information is also discussed in the paper presented at this meeting on capture.

As can be seen, there is good agreement on the costs of post-combustion (coal) plant, which is not surprising as this is the most well established technology. The data for post-combustion (gas) plant is also in fairly good agreement, providing similar gas turbines are used in each study. There is more range in the pre-combustion (coal) plant data, reflecting the number of design options that exist for this technology which is at an earlier stage in its life. The number of published studies on pre-combustion (gas) is limited so data from the IEA Greenhouse Gas R & D Programme has been introduced here as an example for the sake of completeness.

As to operating costs, Tables 3 and 4 show the contribution to the cost of CO_2 capture as quoted in the IEA Greenhouse Gas R & D Programme study and the data from the EPRI study converted to the same load factors, fuel costs, annual capital charge factors and insurance costs. The main difference is in the cost of chemicals and consumables. Maintenance costs associated with CO_2 capture are similar in the 2 studies for pulverised coal plants but differ significantly in the natural gas studies. Otherwise the miscellaneous cost estimates in the 2 studies agree quite well.

Table 1. Comparison of coal plant performance and capital costs

	Post combustion			Pre-combustion		
	PF (SC)	PF (SC)	PF	IGCC (dry feed F-class)	IGCC (slurry, H-class)	IGCC
Source reference	12	13	14	12	13	14
Efficiency,% (LHV)						
Without capture	45.6	42.5	41.2	46.3	45.2	42.2
With capture	33.0	30.3	30.9	38.2	38.8	36.1
Capital cost, $/kWe						
Without capture	1020	1140	1150	1470	1260	1401
With capture	1860	1980	2090	2200	1640	1909
Additional cost of Capture	830	840	940	730	380	508

Table 2. Comparison of gas plant performance and capital costs

	Post combustion			Pre-combustion
	(F-class)	(F-class)		
Source reference	12	13	14	12
Efficiency,% (LHV)				
Without capture	56.2	55.6	55.0	56
With capture	47.2	43.5	47.8	48
Capital cost, $/kWe				
Without capture	410	510	542	410
With capture	790	1010	1013	910
Additional cost of Capture	380	500	471	500

Table 3. Comparison of miscellaneous costs of CO_2 capture in coal plant (c/kWh)

	Post combustion		Pre-combustion	
	PF	PF	IGCC	IGCC
Source Reference	12	13*	12	13*
Maintenance	0.21	0.18	0.16	0.11
Operating and admin. labour	0.06	0.09	0.05	0.02
Consumables and chemicals	0.18	0.29	0.19	0.01
Waste disposal and by-product credits	0.02	0.04	0.01	
Insurance	0.10	0.09	0.08	0.04
Total other costs	0.57	0.69	0.49	0.17
Fuel costs	0.46	0.45	0.25	0.20

*indicates data from EPRI report adjusted for comparable load factor, fuel costs, capital charges, etc.

Table 4. Comparison of miscellaneous costs of CO_2 capture in gas plant (c/kWh)

	Post-combustion	
Source Reference	12	13*
Maintenance	0.08	0.14
Operating and admin. labour	0.03	0.04
Consumables and chemicals	0.07	0.32
Waste disposal and by-product credits		
Insurance	0.04	0.05
Total other costs	0.22	0.55
Fuel costs	0.25	0.36

*indicates data from EPRI report adjusted for comparable load factors, fuel costs, capital charges, etc.

Transmission of CO_2

Pipelines

CO_2 is largely inert and easily handled. It is already transported in high pressure pipelines - there are about 3000 km of CO_2 pipelines in the world, mainly in North America, which have been transporting CO_2 since the early 1980s. Internationally recognised standards for the design, construction and monitoring of CO_2 pipelines are in place in the USA and Canada. These are typically made from mild steel – a satisfactory process providing the CO_2 is adequately dried before entering the pipe to prevent corrosion. Block valves are placed at regular intervals so that, in the event of leakage, that section of the pipeline can be isolated, thereby restricting the amount of CO_2 released.

To assess the cost of CO_2 pipelines it is necessary to consider factors such as:

- Throughput
- Length
- Onshore or offshore and type of terrain
- Country/region and the regulations applying
- Pipeline inlet pressure

- Number of booster compressors
- Booster compressor inlet and outlet pressures
- Whether an inlet compressor is required
- Pipe diameter

The capital costs of pipelines for transmitting various quantities of CO_2 over various distances are shown in Table 5; operating costs are shown in Table 6 and total cost of transmission in Table 7. These figures have been obtained from information assembled for the IEA Greenhouse Gas R&D Programme by an engineering contractor [Freeman et al, 2002]. In each case it is assumed that the CO_2 is available from the capture plant at a pressure of at least 110 bar. The cost of additional compression over the length of the pipeline, if required, is in included in the calculation – booster compressors have inlet pressure of 80 bar and outlet is 110 bar; pipeline outlet pressure is about 80 bar.

Table 5. Capital cost of pipelines for transmission of CO_2 ($M)

	Length of pipeline	
Throughput	100 km	400 km
0.1 million t/y	9	33
5 million t/y	31	135
50 million t/y	137	753

Table 6. Operating cost of transmission of CO_2 by pipeline ($M/y)

	Length of pipeline	
Throughput	100 km	400 km
0.1 million t/y	1.3	5.1
5 million t/y	5.3	21
50 million t/y	21	110

Table 7. Cost of transmission of CO_2 by pipeline ($/t CO_2)

	Length of pipeline		Specific cost
Throughput	100 km	400 km	$/t/100 km
0.1 million t/y	13	51	13
5 million t/y	1.1	4.2	1.1
50 million t/y	0.4	2.2	0.4-0.5

The strong dependence on scale of operation can be seen in the final column of Table 7, which shows the specific cost per 100 km. To handle the CO_2 from a few 500 MW power plant (i.e. 5 million t/y) costs about $1.1/t/100 km. However, looking at sources smaller than this (e.g. an ammonia plant), if there is only 100 000 t/y available, then the cost of transporting a tonne of CO_2 is considerably greater. However, increasing the capacity by a factor of 10 (to 50 million t/y) only halves the specific costs.

It is typically cheaper to pipe CO_2 than to transmit the equivalent amount of electricity. It would therefore be cheaper to site power stations close to electricity demand and transport the CO_2 as necessary to the storage site.

Ship tankers
Another way of transporting CO_2 would be by ship, as a pressurised cryogenic liquid, for example at a pressure of 6 bar and a temperature of -55˚C. Ships would be more flexible than pipelines, they would avoid the need to obtain rights of way and they may be cheaper, particularly for longer distance transportation. Ships similar to those currently widely used for transportation of liquefied petroleum gas (LPG) could be used to transport CO_2. Some parameters for ships based on the largest LPG tankers currently in use are shown in Table 8 [Ormerod et al, 2002].

Table 8. Logistics of tanker transportation of CO_2

Capacity	22 000 m^3
Design temperature	-55°C
Design pressure	6 bar
Distance for shipment	500 km
Speed of tanker	25 km/hr
Loading/discharge times	10/10 hours
Round trip	3 days
Mean sequestration rate	7300 t CO_2/d
Cost of tanker	$50 million

The cost of transmitting CO_2 in this way is about $2/t CO_2, not including costs of holding tanks at the port and the injection facility [Ormerod et al, 2002].

Storage of CO_2

Geological reservoirs

The cost of injecting CO_2 into geological reservoirs for purposes of storage will depend on the type of reservoir and its physical properties, its capacity for storage, the amount of work necessary to access the reservoir (e.g. depth and number of wells), CO_2 flow rate, and the value of any saleable products generated as a result (e.g. through enhanced production of hydrocarbons). Monitoring of the stored CO_2 will also be necessary.

Because of the number of relevant parameters, there can be a large range of CO_2 injection costs for any given combination of CO_2 sources and storage reservoirs. Thus, whilst it may be possible to estimate costs for individual projects with some confidence, according to some authors the economics of CO_2 storage cannot be estimated with certainty [Allinson and Nguyen, 2002] because of the potentially large variations in these parameters.

The cost of drilling wells depends on the specific technology, the location, the scale of the operation and local regulations, amongst other factors. In one recent study [Schreurs, 2002], a cost per production well was given as 750 k€ (c. $750 000), plus 1.5 k€ for every meter of in-seam drilling for an ECBM project. For an injection well, the cost was given as 430 k€ (c. $430 000). Costs for gas gathering, treatment and compression were 0.54 €cent/m^3, and for water treatment in the case of ECBM were 15 €/m^3.

Gupta et al [2002] examined engineering and economic aspects of three scenarios for geologic storage of CO_2 from refining and chemical facilities in the Midwestern United States. These would involve injection of between 2 and 5 million tonnes of CO_2/year. CO_2 separation costs were not included in the assessment but dehydration, compression, pipeline transport, and injection into the reservoirs were covered. The cost was dominated by capital expenditure, of which the largest component was pipeline cost, the next largest being compression. Overall costs of $17-18/t CO_2 were reported but over 80% of this was due to the pipeline and compression costs, parameters which are treated separately in this paper. It was noted that using larger quantities of CO_2, such as by use of a regional pipeline network, would help lower specific costs.

Estimates of the global capacity for storage in various geological reservoirs have been assembled for the IEA Greenhouse Gas R&D Programme [Freund, 2001]. These data are presented as curves of cost as a function of capacity. Some results are illustrated in Figure 1 for depleted oil fields; this includes an allowance for CO_2 transport costs from likely sources. The effect of enhanced oil recovery can be seen in the negative intercept which results from the income generated due to the extra oil produced as a result of CO_2 injection into these fields. Figure 2 shows the comparable global curve for depleted gas fields – unlike the oil fields case, there is no compensating enhancement of production. Figure 3 shows a similar curve for storage of CO_2 in unminable coal measures, where again there may be opportunities for enhanced recovery of coal bed methane as a result of CO_2 injection.

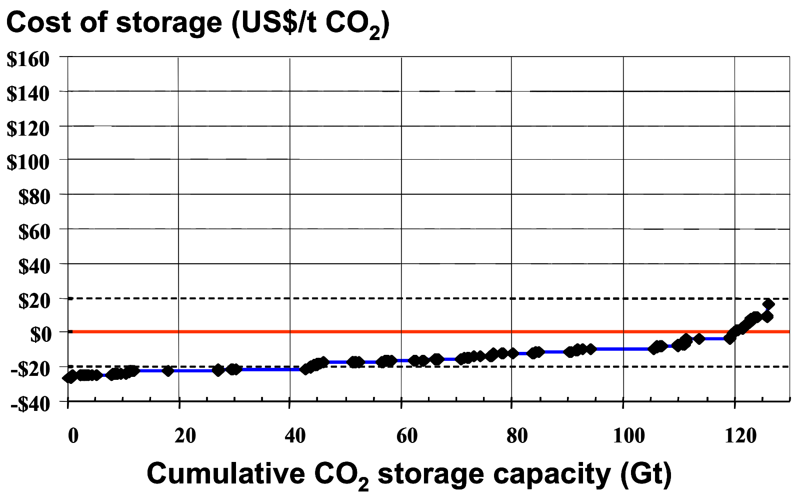

Figure 1. Cost of storage in depleted oil fields

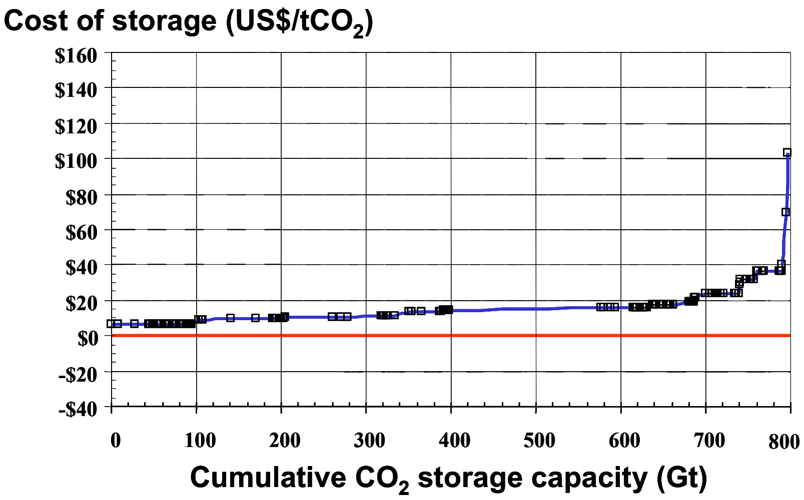

Figure 2. Cost of storage in depleted gas fields

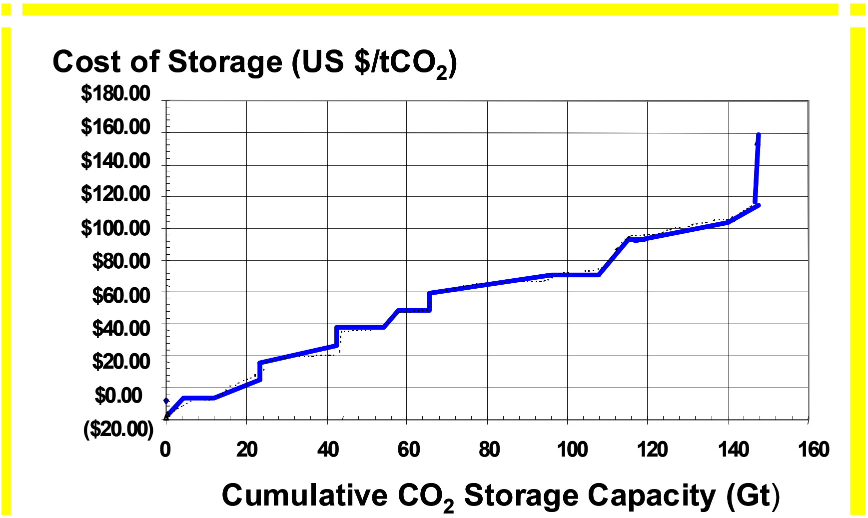

Figure 3.Cost of storage in unminable coal measures

Ocean storage

The cost of ocean storage is, as yet, only approximately determined because the precise mode of injection and the preferred injection depth are not yet clear. Some indication of the cost of injection from work done for the IEA Greenhouse Gas R&D Programme in the early ‘90s is shown in Table 9, based on a conceptual design for a scheme for injecting 19 Mt CO_2/y at a depth of 500m or 3000m.

Table 9. Cost of ocean storage of CO_2 by pipeline

	Injection Depth	
	500m	3000m
Capacity (Mt CO_2/y)	19.0	19.0
Pipeline length (km)	100	100
Pipeline cost ($M)	128	975
Maintenance cost ($M/y)	3.8	3.8
Power consumption cost ($M/y)	3.3	3.3
Total cost of storage ($/t CO_2)	1.1	5.7

Other forms of storage

Various other methods of storage have been proposed, for example:

- As mineral carbonate
- In an artificial store on land
- In methane hydrates with methane recovery

These and other options have been costed for the IEA Greenhouse Gas R&D Programme [Freund, 2001]; some results are shown in Table 10.

Table 10. Cost of other forms of CO_2 storage

Storage as	Cost per tonne of CO_2 stored ($/t CO_2)
Mineral carbonate	*62*
Dry ice in an artificial store on land	*160*
CO_2 clathrate by displacing methane from natural methane hydrates	*510*

In general these costs are very much higher than the cost of storage in geological reservoirs, suggesting that these alternative methods of storage will not be preferred.

Carbon rejection

It has been suggested that processes that extract the energy from the hydrogen content of fossil fuels (with rejection of the carbon content as a solid) would be a potentially attractive method of avoiding CO_2 emissions. Such processes would avoid the need to capture and store CO_2 for many years in a safe repository, although a means of holding or using the solid carbon would be required.

The energy efficiency of the process for thermal decomposition or ‘cracking’ of a fossil fuel, as a means of producing hydrogen will be 50% at best (in theory). In practice, the efficiency could be significantly less because the reaction requires a large energy input. If the rejected carbon were to be used rather than just stored, the process would be a co-producer of energy and a carbon product, thereby helping to offset some of the cost. However, in order to contribute usefully to mitigation of climate change, it would be necessary to find uses for very much larger quantities of carbon black than are currently used worldwide. This would require new applications; the actual mitigation benefit will depend on the fossil fuel displaced by the application so is difficult to assess at present.

A study for the IEA Greenhouse Gas R&D Programme [IEA GHG, 2001] showed that, if the carbon-black has zero value, the cost of hydrogen production is 12.5$/GJ (at a natural gas cost of 2$/GJ). On the other hand, if the carbon produced can be sold at $300/t (the current US price is approximately $800/tonne), the cost of hydrogen would be competitive with producing hydrogen by steam-methane reforming.

As an alternative to seeking a major market for a process in which both carbon black and hydrogen are produced, it has been suggested that a process which integrates decomposition of methane with the production of methanol and electricity could be an effective method of reducing CO_2 emissions. Again the cost depends on what would be done with the carbon black; in the unlikely event that all the carbon could be sold at current price levels, the cost of CO_2 avoided would be $62/t$CO_2$. As there is no known market for the carbon at anything like the scale necessary to have a significant impact on global CO_2 emissions, the abatement cost in practice would be very much greater than this.

Relating costs to emission reduction

Having assessed the cost of capture and storage, it is then necessary to relate it to the abatement capacity. Clearly for a transmission or storage project, the cost can be expressed simply as a function of the amount of CO_2 handled (with suitable allowance for any extra power consumed in the process). However, for the capture process, the amount of CO_2 captured is not the same as the amount of emissions avoided because the energy losses must be made up by extra generation, which gives rise to extra emissions. Thus the proper measure for costing CO_2 capture for abatement purposes is the cost per unit of CO_2 avoided. However, for the purposes of enhanced oil recovery, the appropriate measure would be the cost per unit of CO_2 captured. In this report, the former measure is used.

Comparing costs and benefits over time

This seemingly simple comparison is, in fact, the source of much confusion since different groups report this is different ways, sometimes without explanation.

Economic assessment of a greenhouse gas abatement option will require consideration of the following factors:

- The timing of costs and emission abatement (as these will be different)
- The method of relating costs and benefits
- The baseline for comparison
- The effects of emissions of different greenhouse gases.
- The amount of abatement which can be achieved

It is generally accepted that society places lower worth on economic resources and costs in the future than at present. An accepted method of presenting costs normalised to a standard year is to use discounting procedures. Broadly, two different approaches are taken to setting discount rates. The first is based on the view that the discount rate should be set at the marginal rate of return on investment in the economy, since this represents the opportunity cost of capital. This is the rate of return which could be obtained by investment in the next best project. For example, in the U.K. in the 1990s this rate was around 6-8% [Pearce and Ulph, 1995]. In developing countries, where capital resources are judged to be particularly scarce, it is often higher - the World Bank commonly uses discount rates of 8-12% for economic analysis of projects in developing countries [Sathaye and Meyers, 1995]. These are real rates of return, i.e. they are quoted after removal of general inflation.

The second approach for estimating the discount rate derives from what is known as the social rate of time preference, which depends on society’s preference for consumption now rather than consumption in the future (if all individuals, including those living in future generations, are assumed to be equally important, this preference should be zero; in practice, most people give greater weight to the current generations than to generations in the distant future). This is modified by a factor reflecting the rate of growth in per-capita-income but allowing for the fact that extra income in future will be worth less to an individual than income at the present time. Values for the social rate of time preference, based on empirical estimates, are usually of the order of 1.5 to 2.5% [Cline, 1993] but rates for individual countries will vary.

In accordance with the normal practice of the IEA Greenhouse Gas R&D Programme, future costs and benefits are discounted here at the opportunity cost of capital, typically 10% (sensitivities are often performed at 5% and 15%). This is felt to be appropriate for projects which have lives typically no more than 40 years.

Published studies normally use one of 3 methodologies to account for the timing of costs and of emission abatement:

- Costs are discounted to the present and related to total emission reduction over the life of the project (net present cost)
- Costs are discounted throughout the life of the scheme, to the time when the CO_2 abatement takes place (levelised cost)
- Costs and CO_2 abatement are discounted to the present (net present value).

The first method suffers from the disadvantage that the timing of greenhouse gas abatement is not taken into account even though that can be just as important as the timing of costs. Many published studies of forestry schemes [see for example, Watson et al, 1996, or Sedjo et al 1995] have presented un-discounted costs or discounted net present costs, although a few have presented levelised costs [Richards et al, 1993]. The second and third methods give equivalent results. Some people may argue that only costs can be discounted [World Bank, 1998] not emissions or abatement - if so, levelised costs avoids this conceptual problem. This is the method used in the IEA Greenhouse Gas R&D Programme's comparisons of greenhouse abatement technologies and many other studies of power generation options. Some authors consider that greenhouse gas emissions, if discounted, should be discounted using a lower rate than that used for costs [Marland et al, 1997]. However, low discount rates are not appropriate for short term comparisons of different abatement technologies.

The effects of different discounting methodologies on the costs of CO_2 capture and storage in a power station design [Davison and Freund, 1999] are illustrated in Figure 4. The main differences are between costs discounted to the start of the scheme (net present costs) and costs discounted to the time of sequestration (levelised costs). At a 10% discount rate, these costs differ by a factor of 3.6:1 in this example; at 2% discount rate, the difference is smaller but still significant.

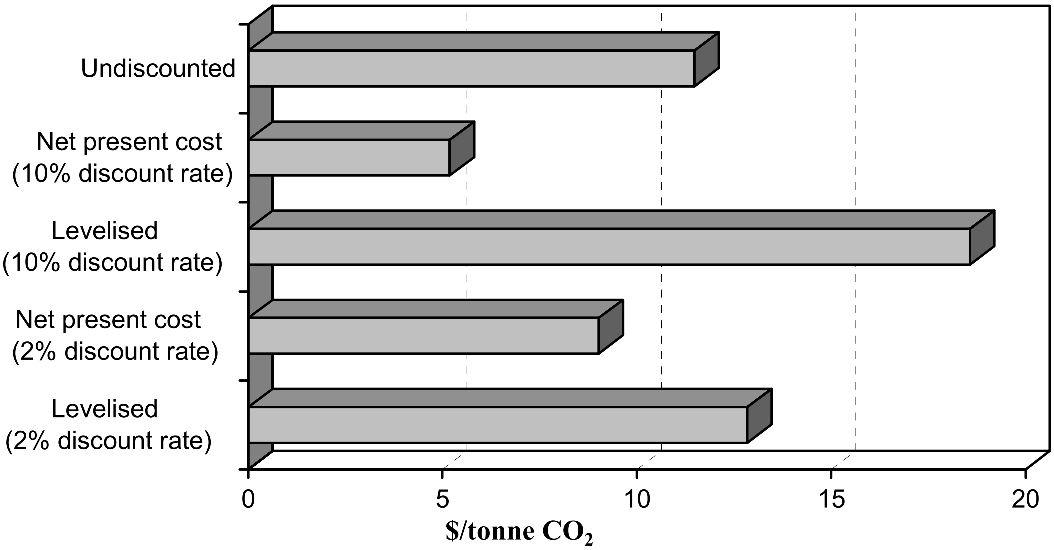

Figure 4 Sensitivity of the abatement cost to discount rate and methodology

Such widespread use of different discounting methodologies can lead to considerable confusion about the relative costs of different greenhouse gas abatement options. It is therefore very important to ensure that the same methodology and assumptions have been used in the assessment of costs of different processes, if the results are to be compared. In this paper, levelised costs are used.

Overall costs of capture, transmission and storage

The additional cost of capture of CO_2 from a new $500MW_e$ power plant, with storage of CO_2 in a geological reservoir is shown in Figure 5, using either coal or gas fuel, showing the main contributions to additional cost. Cost of transmission of CO_2 and storage of \$8t/CO_2 is included. The variation in cost of avoided-CO_2 as a function of fuel costs is shown in Figure 6.

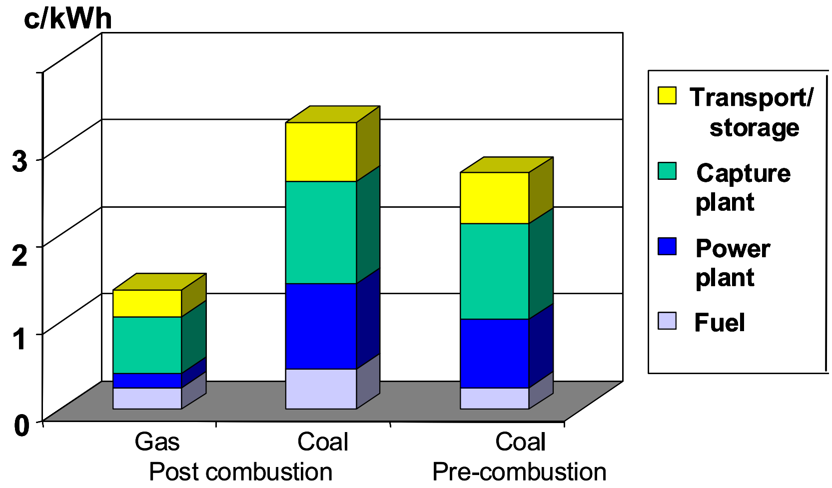

Figure 5 Additional cost of generation due to capture, transmission and storage of CO_2

Potential cost reductions

The main contributor to the cost of this mitigation option is the cost of capturing the CO_2, so opportunities for cost reduction are most sought in this area. As well as improvements in performance or finding less expensive ways to build and operate the capture equipment, the main options are to change the method of capture or to change the process. As more of this type of plant is constructed, there will also be economies of scale in construction and further economies of scale will arise from using larger units. Many of these changes are recognised under a generic phrase ‘technology learning’, a technique which can give an overall impression of the cost reductions achievable over time based on past examples of similar technologies.

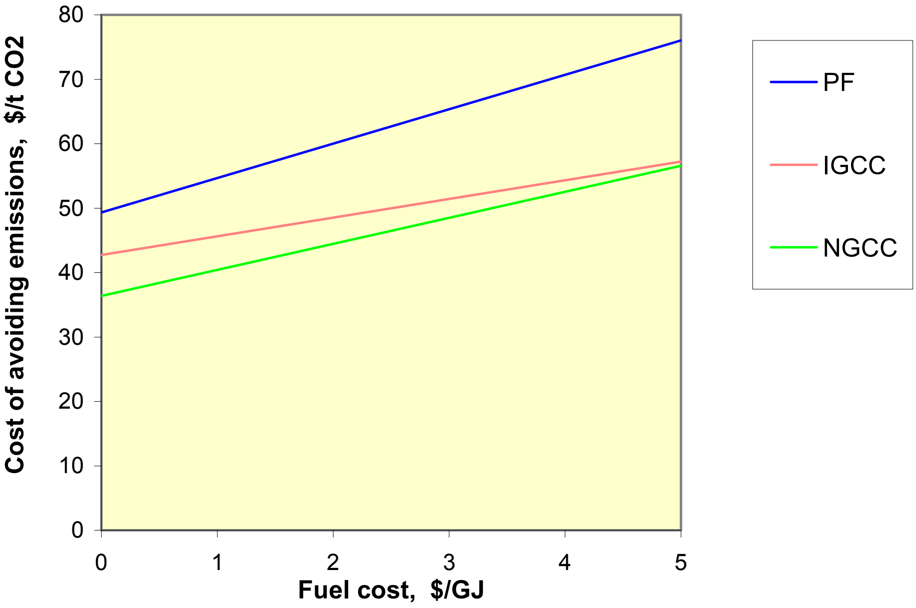

Figure 6 Cost of avoided emissions from use of capture and storage as a function of fuel cost (plant with capture compared against similar plant without capture)

Similar reductions will apply in the other areas of the process but to lesser extent. Economies of scale will certainly affect the cost of transmission (as shown in Table 7). Also, to some extent, there will be opportunities for technology improvements in injecting and managing CO_2 underground.

Technology improvements
Developments in capture technology have been reviewed in the accompanying paper on capture. Several opportunities for improving performance and reducing cost were predicted by the Coal Utilisation Research Council [cited in Herzog and David, 1999] for 2012 – in the IGCC case, specific capital costs were predicted to be reduced by over 10% and efficiency to increase by more than 10%. Similar but smaller changes were predicted in NGCC and PF plant as these technologies are more mature than IGCC. Incremental cost of electricity production was predicted to be reduced by 10%. Others have suggested even greater improvements are possible, especially in the case of developing technologies such as IGCC.

Economies of scale
Many of the assessments described here assume quantity production and installation of the technology. For this reason, the first plants built will probably be more expensive than indicated but, as and when sufficient plants are built to achieve large-scale abatement of emissions, the cost will likely fall below these values because the specific cost of larger plant will be lower than that of smaller plant (similar remarks apply to pipelines too). Another contributor to lower costs will be the savings achievable by building these plants in larger numbers, through larger production runs for the components and by amortising development costs over a larger number of units.

Technology learning
Improvements in performance and reductions in cost of various technologies have been captured by modellers in mathematical relationships called ‘experience curves’ or ‘learning curves’. These are empirical relationships describing the cost of the latest increment of capacity as a function of total installed capacity. Although CO_2 capture systems have not been installed in sufficient capacity to permit this type of analysis, the analogous technology of flue gas desulphurisation provides some indication of the likely effect; NO_x control technologies provide another source of data. A recent review [Rubin et al, 2002] has derived experience curves from a series of studies performed by the same organisation at different times. For both FGD and Selective Catalytic Reduction (SCR), it was found that doubling of installed capacity was associated with a reduction in capital cost of 11-12%. Over the past 10 years, the specific cost of FGD has been reduced by 20% [Boward and Brinkmann, 1998]. Going even further back into the history of FGD, specific cost was reduced by 75% in 30 years from 1970.

Discussion

This paper has examined the cost of capturing CO_2 from power plant together with the cost of transmission by pipeline or other means to the storage site as well as the cost of storage. There are many possible storage reservoirs but the ones most likely to be used in the foreseeable future are geological reservoirs. The cost of monitoring storage has not been included explicitly but, in relation to the quantities of CO_2 stored in a full-scale project, monitoring and verification of storage is likely to be only a small part of the overall cost although little has been published on the cost of such activities.

This paper has examined the costs of post-combustion and pre-combustion capture techniques but has not considered oxyfuel processes or any other more speculative concepts since the design of these processes has not yet been established with sufficient accuracy to enable them to be costed with as much confidence as the two established processes. However, it is expected that the cost per tonne of CO_2 avoided would be similar for post-combustion capture, pre-combustion capture and those oxyfuel processes which have so far been demonstrated.

There are various other sources of CO_2 which may be suitable for capture, such as energy intensive industry. Indeed some CO_2 sources are suitable for capture with much less cost penalty than those shown here (for example see the paper by John Gale presented earlier in this meeting).

Only new build power plant has been considered as this provides a more straightforward basis for costing so the results can be interpreted more easily. New build also has advantages over retrofit application in that the plant would have longer life and the efficiency would be higher. Nevertheless, projects are being developed based on retrofit of existing power plant [Markussen et al 2002], where high efficiency plant is available. Further studies are underway, for example in Canada [Campbell and Richards, 2002], to assess a range of retrofit options. Because the efficiency of existing plant tends to be less than that of new plant, and the remaining life shorter (so reducing the period over which the extra investment can be recovered), the additional cost of capturing CO_2 tends to be higher for retrofitting of CO_2 capture equipment than for fitting such equipment as part of a new plant, which is the basis used for the figures shown here. Although comparative costings of retrofit and new build using similar bases have not yet been published, those analyses so far available [e.g. Bozzuto et al 2001] support these conclusions.

Expressing the cost of these plant in terms of \$/t CO_2 avoided takes into account the additional energy (and emissions) resulting from capturing CO_2. However, as a means of comparing mitigation options, this measure can be confusing since the answer depends strongly on the base-case chosen for comparison. Hence, unless there is a clear definition of the base case, it is recommended that the cost of systems with and without capture should be presented in terms of cost of generation (e.g. \$/MWh) and the emissions per unit of electricity generated (e.g. t CO_2/MWh), rather than in the reduced form of \$/t CO_2 avoided.
Most of the published studies of specific projects consider particular sources and storage reservoirs. Necessarily these use costs appropriate to particular plant, so that the quantities of CO_2 involved are only a few million tonnes per year. Although these are realistic quantities for the first such projects, they fail to reflect the economies of scale which are likely to be appropriate when this technology is used for mitigation of climate change - under those circumstances, very much greater quantities of CO_2 would have to be transported and stored, leading to commensurate reductions in costs.

Conclusions

Systematic evaluation of processes for capture and storage of CO_2 can answer a number of questions, such as about the relative attractiveness of different processes, and about how these compare with other mitigation options. In order to do this, comparable methods of assessment and similar assumptions are necessary and these must be clearly stated if the comparison is to have any value.

The options discussed in this paper are all based on fairly well established technology so the costs can be estimated with reasonable confidence. The results have been presented for large scale application, as would be appropriate for tackling climate change, but will not be representative of first-of-a-kind plant or small scale applications. The cost of avoiding CO_2 emissions is relatively similar (compared with a baseline of current build) for all of the processes considered. Deep reductions in emissions could be achieved using this technology at a cost (in large scale application) comparable with other methods for achieving such reductions.

Acknowledgements

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Carbon Capture and Sequestration: Potential Environmental Impacts

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Abstract

Over the last few years, understanding of the profound implications of anthropogenically driven climate change has grown. In turn, this has fuelled research into options to mitigate likely impacts. Approaches involving the capture of carbon dioxide and its storage in geological formations, or in marine waters, have generated a raft of proposed solutions. The scale of some of these proposals is such that they will exert impacts of global significance in their own right.

Proposals fall into two broad categories:
- storage of liquid CO_2 or products of reacted CO_2 into intermediate/deep oceanic waters.
- storage of liquid CO_2 into sub-seabed or terrestrial geological formations.

For the most part, while the technical feasibility of these schemata has been widely explored, the same is not true of their ecological implications. In the case of deep/intermediate oceanic waters, poor baseline understanding of the associated ecosystems is a considerable impediment to any reliable predictive assessment of likely impacts of carbon dioxide storage in these systems. Disruption of marine microbiological processes and degradation of benthic ecosystems, including those with high levels of endemicity, have been identified as potentially serious impacts. Similarly, the physiology, ecology and likely responses of micro-organisms present in targeted geological formations require evaluation prior to any consideration of the use of such formations for storage of CO_2. In addition, the impacts of any leakage to surface need also to be considered.

Accordingly this paper explores current uncertainties and detailed informational needs related to ocean and geological storage of fossil fuel-derived CO_2. Particular emphasis is placed upon the ecological impacts of these proposals in relation to existing and emergent understanding of deep water/soil ecosystems and the indeterminacies attached to this understanding.

Introduction

The capture of carbon dioxide generated by fossil fuel combustion, coupled with its subsequent storage into free circulating oceanic waters or sub-seabed/terrestrial geological formations, has been proposed on a number of occasions and is currently the subject of discussion at government level in a number of countries (see e.g.: DTI 2000). As such these schemata are part of a raft of planetary engineering approaches to climate change mitigation. Some of these are illustrated in Figure 1 below:

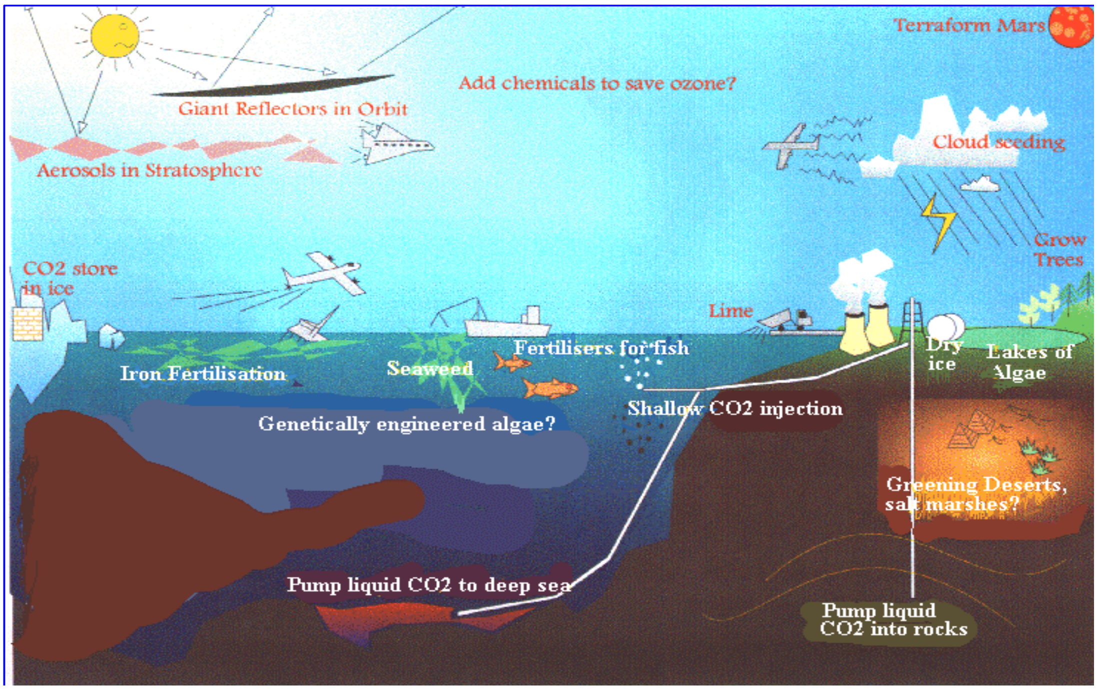

Figure1 Schematic representation of various proposals which have been made to mitigate anthropogenic climate change through planetary engineering projects. Source: Matthews (1996), reproduced by permission.

As a component of this raft of potential solutions, the idea is to develop ocean/geological storage systems as a means of mitigating the impacts of anthropogenically driven climate change. Effective mitigation by these means implies the need for effective isolation of the captured CO_2 over long time frames. The potential quantities which may be stored by any given ocean or geological scheme have been estimated and are reproduced in Table 1 below:

Table 1 estimates of carbon reservoirs of different biosphere compartments and order of magnitude estimates of potential capacities for carbon sequestration (adapted from Herzog 2001)

Reservoir size	**Gt (billion tonnes) carbon**
Oceans	44 000
Atmosphere	750
Terrestrial	2 200
Sequestration potential	**Gt (billion tonnes) carbon**
Oceans	1000s
Deep saline formations	100s-1000s
Depleted oil and gas reservoirs	100s
Coal seams	10s-100s
Terrestrial	10s

On the basis of these data, it appears that the oceans and saline aquifers present the greatest opportunities for storage of anthropogenically derived CO_2. The rationale behind the major proposals is outlined below.

The proponents of these large scale planetary engineering projects assert that such approaches are consistent with the United Nations Framework Convention on Climate Change (UNFCC) which 'explicitly mentions the need for using sinks and reservoirs as one component of a more comprehensive portfolio of strategies for reducing greenhouse gas emissions' (Adams *et al.* 2002). It should be noted, however, that the UNFCC also explicitly enjoins parties to manage such sinks in a sustainable manner.

Moreover, in addition, there are legal instruments which specifically impinge upon the use of the deep ocean to store fossil fuel-derived CO_2. On an international basis the London Convention (1972) prohibits the dumping of industrial waste at sea or in sub-sea bed formations. More regionally, the OSPAR Convention (1992) reinforces and extends the provisions of the London Convention within the North East Atlantic area. The question of whether ocean carbon storage constitutes a regulated activity under these Conventions, and in particular whether fossil fuel-derived CO_2 constitutes an industrial waste, needs to be urgently resolved.

Schemata to capture and store carbon dioxide either in ocean systems or geological formations have in common the capture phase of operations followed by liquefaction and transport. The environmental risks associated with this phase are not considered in detail in this current paper. These risks can largely be described in terms of probabilistic likelihood of process engineering failure, or failure of the CO_2 transport infrastructure. There is considerable operational experience of both the process engineering involved in capture and in the transport of CO_2 by pipeline. The most serious impacts are likely to result from failure of transport pipelines and a large release of carbon dioxide in gaseous form. It is possible that such releases could endanger human life and those of livestock. A natural (though extreme) analogue is that of Lake Nyos, a volcanic crater lake in Cameroon which outgassed large quantities (estimated at 80 million cubic metres) of carbon dioxide causing 1700 deaths and loss of livestock up to 25km from the crater (Kling *et al.* 1994, Clarke 2001).

Ocean Storage Options and Potential Impacts

i) The Oceans and the Global Carbon cycle

The rationale behind ocean storage of carbon injected as liquid CO_2 is described by GESAMP (1997) as essentially:

'a short-circuit mechanism that disposes of fossil-fuel combustion CO_2 directly into the deep ocean, thereby reducing direct injections to the atmosphere and accelerating the process of attaining of atmosphere-ocean equilibrium. It can be viewed as an acceleration of the natural, but slow, process of transferring CO_2 from the atmosphere to the deep ocean which is currently estimated to be occurring at a rate of 2 Gt C per year'.

Accordingly, wide-scale adoption of ocean storage is viewed as a means potentially of avoiding the 'transient' high peak of atmospheric CO_2 predicted for the next few centuries arising from projected future emissions (IPCC, 1996). Ultimately, the equilibrium reached with the atmosphere (over many centuries), it is argued, would be about the same as that which would have occurred without intervention. Such proposals are specifically predicated upon the basis that it will be possible to capture the carbon dioxide emitted from the majority of the world's power stations and transport it for injection into deep water (GESAMP 1997). Given continued development of fossil fuel power generation, a yearly commitment to store around 7Gt of CO_2 is not an unrealistic projection.

The global carbon cycle can be visualised schematically as in Figure 2 above while the various anthropogenic emission sources quantified by the IPCC (1996) in summarised in Table 2.

Atmospheric carbon dioxide is transferred rapidly into seawater at the air-sea interface, particularly when strong winds cause breaking waves and entrainment of bubbles. As a result of the chemical equilibrium between molecular carbon dioxide and the bicarbonate and carbonate ion present in seawater, only around 1% of the CO_2 remains in dissolved molecular form with the rest being converted to bicarbonate ion. Once the carbon dioxide has become dissolved into the surface waters it enters the marine carbon cycle and may ultimately be transported into deep waters by two major processes, the solubility and the biological pumps.

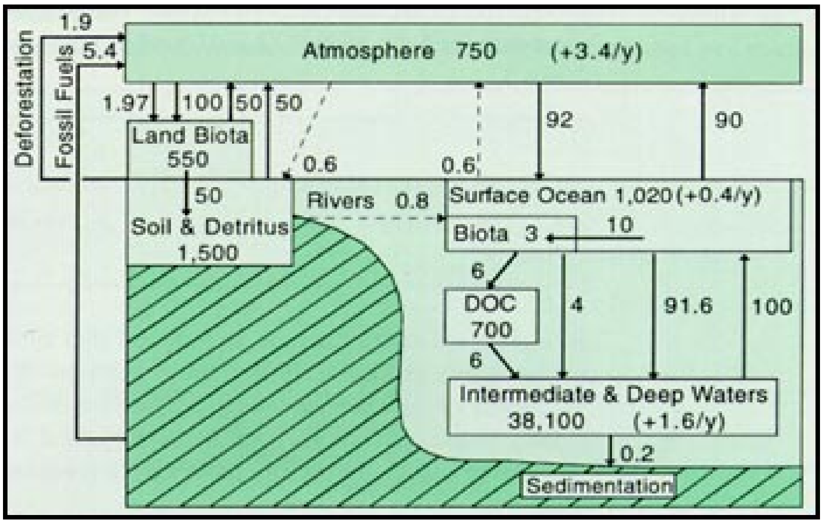

Figure 2 Schematic representation of the global carbon cycle for the 1980's. Fluxes are given in GT y^{-1}, reservoirs in Gt. The figures in parentheses indicate the increase in given compartments of carbon on an annual basis due to anthropogenic carbon dioxide emissions. See also legend to Table 1 and body of text. Source: IEA (1998a) Reprinted from Siegenthaler and Sarmiento (1993)

The basic chemical reactions determining CO_2 assimilation in seawater and ocean systems are as follows:

$$CO_{2\,(gaseOus)} \overset{kO}{\leftrightarrow} CO_{2\,(aqueOus)}$$

$$CO_2 + H_2O \overset{k_H}{\leftrightarrow} H_2CO_3 \overset{k_1'}{\leftrightarrow} H^+ + HCO_3^- \overset{k_2'}{\leftrightarrow} H^+ + CO_3^{2-}$$

where kO = the solubility coefficient of CO_2 in seawater, k_H is the hydration constant and k_1' and k_2' art the apparent first and second dissociation constants of carbonic acid. The carbonate ion is an important measure of buffering capacity, and therefore capacity to neutralize CO_2 entering seawater through the reaction:

$$H_2O + CO_2 + CO_3^{2-} \leftrightarrow 2HCO_3^-$$

CO_2 can also be neutralized by calcium carbonate in suspended particulate form or incorporated into sediment through the reaction:

$$CO_2 + H_2O + CaCO_{3(sOlid)}\ \varsigma\ Ca^{2+} + 2HCO_3^-$$

This reaction can take place with biogenic calcium carbonate present in both living and dead calcified organisms.

Under deep ocean conditions, CO_2 hydrate (clathrate) may form as CO_2**.** $6H_2O$ or CO_2**.** $8H_2O$. This is thought to form around droplets at depths greater than 500m. This is regarded as an interfacial stage, whereas the formation of a clathrate boundary around CO_2 present as a lake on the bottom of the ocean is likely to be more stable and inhibit CO_2 dissolution over longer timescales.

Table 2: Global carbon budget for post industrial times showing major emission sources and uptakes in $PgCy^{-1}$ (Gt). Discrepancies between the figures cited in this table and those cited in Figure 2 and in the text arise from the considerable uncertainties attached to estimates of carbon fluxes and reservoirs Source: IPCC (1996)

Emissions	PgC/yr
Fossil Fuels	5.5±.5
Tropical Deforestation	1.6 ± 1.0
Uptake	PgC/yr
Atmospheric Buildup	3.3
Ocean Uptake	2.0 ± 0.8
Forest Regrowth (NH)	0.5 ± 0.5
Land Sink (by difference)	1.3 ± 1.5

Even with the current uncertainties which exist in relation to the size of carbon reservoirs and fluxes, simple calculations based upon the actual concentration of CO_2 and the theoretical saturation achievable in deep ocean waters indicate a notional capacity for several million Gt of CO_2. In practical terms, this is constrained by the amount of carbonate ion available to neutralise the carbonic acid formed by dissolved carbon dioxide if large excursions in overall oceanic pH values are to be avoided (see below) Estimates for carbonate available in deep ocean sediments range between only 1,600 Gt and 4,920 Gt. Dissolved carbonate ion in ocean waters deeper than 500m have been estimated at 1,320 Gt. It must be stressed that these values are highly speculative due to the paucity of empirical data (see: Wong & Hirai, 1997). Nevertheless they have spurred much research into how CO_2 might be injected into deep ocean waters and stored there.

The carbon cycle in the ocean is based upon interactions between physical, chemical and biological processes. These processes are understood in individual terms to varying extents, but the interactive aspects are subject to extremely large uncertainties (Falkowski *et al.*2000). In large part this is due to poor spatial and temporal resolution of understanding of these processes in the ocean despite the data generated by large ocean research programmes on this topic and to the resultant inadequacies of the mathematical models applied to such studies (Follows *et al.,* 1996; Ormerod, 1996). CO_2 uptake from the oceans has largely been inferred from calculations based upon sparse total inorganic carbon measurements. Improving the precision of these estimates by suitably intense sampling programmes is likely to be some decades into the future (Goyet *et al.,* 1997). Hence, current published notional annual uptake estimates for CO_2 range between 1.5 and 3.1 Gt. The question of how and where anthropogenic CO_2 penetrates into the ocean will remain unanswered until additional field measurements are available covering all areas of ocean within the depth of the winter mixed layer at an appropriate spatial resolution. In many respects this question is allied to the questions concerning the likely retention time of carbon dioxide injected into the ocean.

Considerable indeterminacies attach to the interrelationships of other biogeochemical cycles with the carbon cycle. Accordingly there is a great need to continue to gather baseline data on the global carbon cycle, to disentangle the inter-relationships and to quantify the carbon fluxes, sinks and reservoirs involved. Reliable quantification of these may prove somewhat challenging given that in some cases possible changes cannot yet even be ascribed a positive or negative dimension, much less a magnitude. It is quite possible too (Falkowski *et al.* 2000) that the existing natural sinks involving the ocean will be diminished under a climate change scenario..

ii) Injection of CO_2 into ocean waters

Essentially, the proposals for storage of CO_2 in the oceans hinge around two basic methods of introduction of the gas as a liquid, illustrated in Figure 3. Both systems essentially introduced CO_2 into the oceans in an uncontained form so that CO_2 dissolves and ultimately re-enters the carbon cycle. Plans to store quantities of solid carbon dioxide either in cold terrestrial regions, or by discharging blocks of ‘dry ice’ from ships seem largely to have disappeared from active consideration. A further scheme proposed for marine storage involves the reaction of CO_2 with limestone and water to produce bicarbonate which can then be discharged to the ocean, thereby mitigating against limitations in carbonate neutralisation capacity (Rau and Caldeira 1999; Caldeira and Rau 2000). This scheme does not appear to be as evolved as those involving direct introduction of CO_2 to the oceans. Accordingly, this paper considers only the scenarios outlined in Figure 3. The injection scenarios have been described in a number of documents (see: Johnston *et al.* 1999; Herzog, 2001).

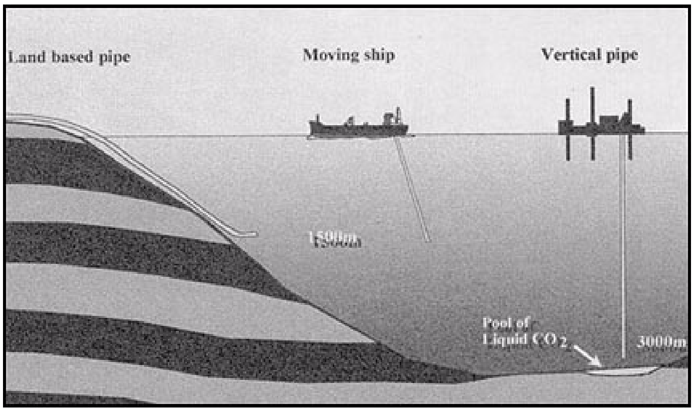

Figure 3: The proposed introduction of liquid carbon dioxide from a fixed or towed pipeline into mid ocean waters and the discharge of liquid carbon dioxide onto the seabed from a fixed platform. In practice ships could be used in place of the platform to create a seabed lake of CO_2 also. Source IEA (1998a).

Mostly, research effort has focused on the introduction of CO_2 by pipeline. At depths of less than 500m, introduction of CO_2 will create bubble plumes since, at ambient pressures and temperatures, carbon dioxide exists as a gas. These bubbles will dissolve in the seawater and, it is suggested, become trapped below the ocean thermocline. Although in engineering terms this is a relatively simple option, the retention time of the gas would be relatively short, of the order of 50 years (see: GESAMP 1997). At temperatures and pressures between 500m and 3000m, carbon dioxide exists as a positively buoyant liquid. Hence, it will form a droplet plume, perhaps with the droplets covered in film of hydrate, which could slow dissolution (Drange *et al.* 2001). Injection into intermediate depth waters is assumed to result in a CO_2 enriched plume where diminished pH values are likely to persist for many tens of kilometers down current, depending upon the degree of constraint imposed by, for example, density discontinuities. It is possible that in this case hydrate formation could inhibit the uptake of CO_2 in seawater if it results in a plume of droplets, which rise to the hydrate phase boundary (Brewer *et al.* 2000).

The injection of CO_2 into deep oceanic waters is likely to have qualitatively different impacts as compared to introduction into intermediate depth waters. Below 3000m, it is anticipated that CO_2 will form a dense liquid plume which could ultimately form a lake of liquid CO_2 on the sea bottom (Adams *et al.,* 1995; Brewer, 2000) bounded by a clathrate surface. This surface will inhibit (though not prevent) its dissolution into the overlying waters. Retention times in these cases should be much greater than those achieved by injection into shallower water since deep water exchanges with surface water at a much lower rate than surface water interacts with the atmosphere in the upper mixed layer of the sea. Calculations have suggested that a lake of CO_2 on the deep ocean floor derived from 1GW of coal fired power plant over ten years of operation could cover $654{,}500m^2$ of sea floor to a depth of 80.9m and contain 58 million tonnes of the liquefied gas (Wong & Hirai, 1997). The assumption that the pool would remain 80.9m in depth is merely a hypothetical construct to operate the mathematical model. Unless constrained by local topography or the formation of a clathrate boundary it seems reasonable to assume that, in practice, the liquid CO_2 might spread out to form a thinner layer over a much wider area, with the consequence of more widespread impacts. This would depend upon the degree to which any hydrate formation (see below) constrained the CO_2. Eventually, however, ocean processes will dissolve all forms of dumped CO_2 and transport it ultimately towards the surface. It has been estimated that, at a depth of >3000m, a pool of CO_2 containing 58.4 Mt would dissolve into the deep water over approximately 240 years.

iii) Resultant physico-chemical modification

Normal pH values in seawater are 8.0-8.2 at the surface, decreasing to 7.7-7.8 in deep water (Train 1979). In some productive tropical environments, pH values may embrace a daily range of 7.3-9.5 as a result of biological sequestration.

Irrespective of the considerable pH buffering provided by seawater *via* the carbonate system (and to a lesser extent other weak acid salts such as borate), the introduction of large quantities of CO_2 directly into the deep ocean will modify the water pH locally to a significant degree. In addition, an elevation of free carbon dioxide can be anticipated. Moreover, if the CO_2 contains impurities (as would seem likely for many industrial waste streams) such as sulphur oxides, nitrogen oxides, trace metals or organic chemicals then the behaviour and impact of these will need to be considered in addition to the impact of pH change alone.

Models suggest the pH excursions likely to result from introduction of CO_2 are substantial (IEA 1996, partially reproduced by GESAMP 1997). These figures suggest that a pH of below 7.5 would exist through some 1500 cubic kilometres of water if the CO_2 from ten power plants was introduced at a single point as a droplet plume and that this would rise to 5900 cubic kilometres if introduced as a dense plume in shallower water. The centre-line distances from the point of release to reach a pH value of 7.5 are 530 and 2200 kilometres respectively.

v) Potential Impacts

On the basis of the above, potential impacts upon marine biological systems which need to be considered are those due to:

- pH reduction
- carbonate dissolution
- co-recovered materials such as sulphur oxides, nitrogen oxides and metals
- changes in speciation of e.g. metals and ammonia.
- ‘smothering’ effects

In predicting the extent of likely impacts it is necessary to establish baseline datasets relating both to the scale and extent of the physico-chemical perturbation and the character of the biological systems involved. As noted above, current prediction of pH excursion is based upon mathematical modeling. It is unlikely that the technological means will exist to generate precise *in situ* data sets over a relevant (*i.e.* extensive) spatial scale for pH changes in the deep ocean resultant from CO_2 storage. With respect to availability of baseline data sets required to evaluate biological impacts, much depends upon the level of biological organization involved. This is illustrated in Figure 4:

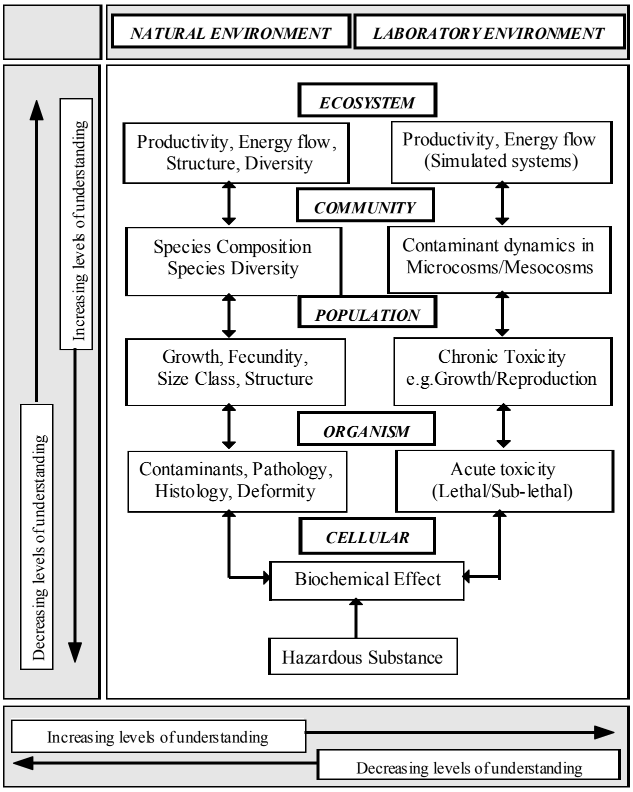

Figure 4: Schematic diagram showing levels of biological organization and associated biomarkers of toxicological impact at each level. Levels of scientific understanding tend to decrease in relation to natural as opposed to laboratory systems and with increasing levels of biological organization. Source: Santillo et al. *(1998)*

In general, impacts of physico-chemical changes upon living systems tend to be assessed using single species toxicity tests, the results of which are then extrapolated to predict whole ecosystem impact (see: Santillo *et al.* 1998). The biological markers of effect employed (biomarkers or endpoints) are predominantly cellular, organismal, and less commonly, population (*e.g.* sentinel species). Few reliable markers have been identified at the community and whole ecosystem level. This is an acknowledged problem that pervades the whole field of environmental toxicology. While regulatory endpoints have been defined for many situations, their relevance as significant systemic biological endpoints is often highly questionable.

In the case of deep sea environments, even relevant species data are very sparse. It is widely acknowledged that, in ecological terms, the deep oceans are poorly understood. In recent years the paradigm under which deep sea environments have been characterized as homogenous, sparsely populated and lacking in diversity has been challenged by the discovery of hydrothermal vent ecosystems, cold seep systems, seamount ecosystems, coldwater coral reefs and gas hydrates (Roberts 2002). Seamounts, for example, have been found to be hotspots of diversity, with a high proportion of unique species (Koslow *et al.* 2000; 2001). These topographical features are numerous. To our knowledge, no toxicological endpoints/biomarkers exist for any of the species present in these various ecosystems. Even if they did, extrapolation of findings to predict impacts on the wider ecosystems would not be possible since the community structure and dynamics of these systems are so poorly characterized. It is only recently, for example, that knowledge of species distribution in the oceans has advanced to the point where basic hypotheses concerning the existence of latitudinal biodiversity gradients have been able to be tested (Gray 2001).

Some work on disturbance of faunal communities has been carried out in the deep ocean, specifically the analysis of pre-and post disturbance characteristics of the meiobenthic fauna impacted by potential deep-sea mining activities (Ahnert & Schriever 2001; Vopel & Thiel 2001). These studies are analogous to meiofaunal studies carried out in shallower waters (Warwick 1988) to identify pollution impacts. This fauna, comprised of extremely small species, generally lends itself to detailed statistical analysis. Even so, in the deep-water studies, the lack of replicates prevented even some fundamental components of analysis (*e.g.* depth distributions of organisms) being carried out.

The use of very small organisms allows resolution of physical impacts over relatively small areas. It is not clear how these techniques would translate to the much bigger areas likely to be impacted by deep ocean storage of CO_2 . Overall the lack of general baseline information on deep-sea ecosystems and their likely responses to perturbation, along with the difficulties inherent in working with such systems, present a highly important suite of uncertainty and indeterminacy.

a) pH reduction

Existing data suggest that the reduction of marine pH values over a wide area is likely to have appreciable impacts on organisms in deep ocean habitats. CO_2 causes acidification not only in the water to which it is introduced, but also in organismal tissues and body fluids. Intra- and extracellular acid-base parameters will reach new steady state values which, if they do not cause acute effects, could result in chronic metabolic and reproductive impacts. It is generally considered that deep ocean organisms have evolved for life in a physico-chemically stable environment and may be poorly equipped to accommodate and/or avoid changes. While the majority of information on impacts of reduced pH on aquatic organisms relates to freshwater species (see: Train 1979; Wolff *et al.*1988), some data do exist on marine organisms. A common problem with many of the studies carried out on marine fish is a failure to distinguish properly between the effects of low pH and of the CO_2 released by addition of the acid used. Similarly, for other marine organisms, the body of data is hard to interpret since data are scant and other variables were often not adequately controlled. Existing data on pH responses have, however, been synthesized into a predictive model described by Auerbach *et al.* (1997) and Caulfield *et al.* (1997). Most of the biological impact analyses of ocean carbon storage schemata are based upon this predictive model notwithstanding the inherent limitations in the body of biological response data.

The US EPA water quality criterion for pH in marine waters (Train 1979, EPA 2002) was set to maintain it within the range 6.5-8.5 but with the proviso that it should not rise or fall more than

0.2 units outside the normally occurring range. Studies suggest that plankton and benthic invertebrates are more sensitive than fish to changes in pH. Reported experimental work on reduced pH impacts on deep sea organisms appears to be even more limited, restricted to (qualitative) observations made of fish and motile invertebrates exposed to extremely small quantities of introduced CO_2 (Tamburri *et al.* 2000). Some limited work has also been carried out on marine bacterial communities exposed to elevated CO_2, but these were not carried out under deep ocean conditions (Sugimori *et al.* 2001).
In relation to intermediate depth CO_2 injection, one study has been published which investigated the impact of reduced pH upon bacterial processes (Huesemann *et al.* 2002). Specifically, nitrification reactions were suppressed by 50% when pH was reduced from 8 to 7 and by 90% at pH 6.5. This led the authors to postulate wide-ranging impacts upon the cycling of nitrogen in waters influenced by carbon storage activities.

Overall, however, the general paucity of data on pH impacts at the organismal and higher levels of biological organisation must be seen as a further important barrier to current assessment of likely impact of deep ocean carbon storage schemata.

b) Carbonate dissolution

A number of groups of marine animals have shells or skeletal structures based around calcium carbonate. This can be dissolved by reaction with CO_2 in water. Accordingly, some deep-water corals and bivalve molluscs, among other organisms, could be particularly vulnerable to this process. In addition, the neutralization of CO_2 by reaction with calcareous sediments could provoke changes in the sedimentary infauna. No detailed information appears to have been published on this and its biological significance is therefore unknown. If realised, however, widespread dissolution of exoskeletal structures could have profound secondary impacts.

c) Co-recovered materials

While the potential significance of co- recovered materials present with captured CO_2 is acknowledged by GESAMP (1997), it appears that no information is available concerning the significance of this. Impact studies need to take account of the fact that nitrogen oxides, sulphur dioxides, metals and possibly a variety of organic chemicals could be present in the CO_2.

Speciation of other compounds

The speciation and, therefore, biological availability/ activity of various metals and ammonia may be affected by reduced pH. The significance of this in deep marine waters impacted by CO_2 storage is unknown.

d) 'Smothering' effects

As noted above, introduction of liquid CO_2 into the deep ocean to form 'lake' on the seafloor could cover substantial areas of sea floor. It is reasonable to assume that living systems at the seafloor at such points would be obliterated.

iv) Research needs

Research needs attach to many aspects of the likely impacts of carbon dioxide storage in the deep oceans. Requirements appear to be largely to address generic concerns, but site specific considerations will also apply as potential storage sites are identified. Significant uncertainties, knowledge gaps and indeterminacies include:

- Structure and function of deep sea ecosystems
- Effects of reduced pH on deep ocean organisms at all levels of biological organization
- Potential impacts upon biodiversity hotspots (seamounts, hydrothermal vents, seeps etc.)
- Temporal and spatial extent of changed pH regimes and of associated biological impacts
- Identification of relevant and applicable biomarkers of effect of changed pH
- Possible interactions of CO_2 storage with other biogeochemical cycles and onward effects
- Ecological impacts of carbonate dissolution on fauna with calcareous structures
- Ecological impacts of carbonate dissolution on microflora of calcareous sediments
- Extent of ' smothering 'impacts at scale of likely storage operations
- Additive/synergistic impacts of materials co-recovered with captured CO_2 upon biological systems
- Development and validation of models used
- Site specific considerations

2. Storage of CO_2 in geological formations

i) Geological Options

A number of schemata have been proposed involving the use of various kinds of geological formations. These have been summarized by the UK's Department of Trade and Industry (DTI 2000). The use of depleted oil and gas formations to store CO_2 extends from the concept of reservoir flooding for EOR or the re-injection of CO_2 separated from natural gas. The arguments supporting this concept are based around the containment historically afforded by such formations over geological timeframes. Similarly, deep saline aquifers have been identified as natural formations where injection of CO_2 followed by its reaction with minerals to form carbonates would essentially lock up the gas permanently. A similar rationale attaches to the recovery of methane from deep unmineable coals beds where CO_2 would be used to displace the methane and in doing so become 'locked up' in the coal.

Figure 5 schematically represents a system involving the injection of carbon dioxide into a subseabed geological formation. Such an operation is currently taking place in the North Sea Sleipner field and was initiated in late 1996 by Statoil the Norwegian State Oil Company. Around 1 million tonnes of carbon dioxide are being pumped annually into a porous salt water aquifer some 32,000 km^2 in extent (IEA, 1998b). This Utsira sandstone formation lies around 1 km below the sea floor above the gas producing Heimdal formation and below an impermeable shale. Seismic monitoring activities have been emplaced to allow the movement of the gas through the aquifer to be followed. The carbon dioxide in this case is derived from the gas field where the natural gas brought to the surface contains around 9% CO_2. This is reduced to about 2.5% by treatment and the stripped CO_2 is injected into the sandstone formation. This is the first time that injection of carbon dioxide has been practised on such a large scale and the first time that carbon dioxide has been compressed and injected from an offshore platform (Baklid *et al.,* 1996). It is planned to initiate a second project bases on similar technology at an Arctic: the Snohvit field (Statoil 2003).

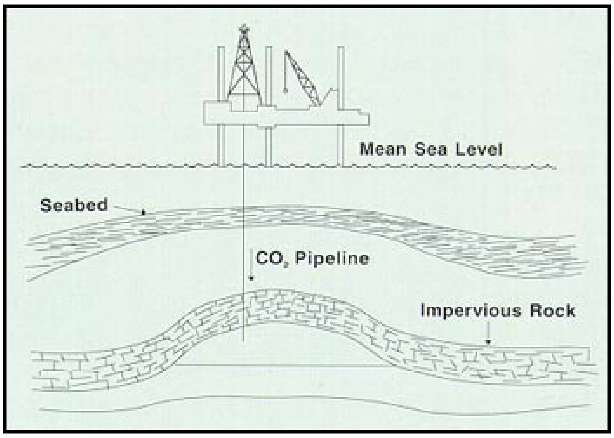

Figure 5: Schematic representation of injection of carbon dioxide into a subseabed formation. This is currently underway in Norwegian waters in the Sleipner field From IEA (1998a)

A similar project is under consideration by a consortium involving Exxon and the Indonesian State Oil Company in the Natuna offshore gas field in the South China Sea. This field is one of the largest in the world and, if the project goes ahead, up to 100 million tonnes of CO_2 would be injected annually into a sub-sea bed aquifer (Hanisch, 1998). In this case also, the CO_2 is removed from the natural gas recovered in which it is present at concentrations of around 70% by volume (Herzog *et al.,* 1997).

Despite concerns about the legality of the current Norwegian marine operations under international law (see: Johnston *et al* 1999) the use of saline aquifers for carbon dioxide storage is conceptually and practically well advanced. It is intended that the CO_2 be isolated permanently from the carbon cycle. While saline aquifers comprise the greatest potential geological CO_2 storage option with a capacity of between 100-10,000Gt CO_2, depleted oil and gas reservoirs also represent a significant potential storage volume. The use of carbon dioxide for enhanced oil recovery purposes is a standard oil industry procedure. In general it appears that schemata for the geological storage of carbon dioxide are at a far more advanced stage than those proposed for storage of carbon dioxide by injection into deep ocean waters. It seems that geological storage options are underpinned by a far more extensive information and database than exists for unconstrained ocean options and this has been consolidated by research projects specifically aimed at identifying and characterising potential geological resources of this kind. (see *e.g.* Holloway 1996).

The research required in relation to the use of geological formations identified as targets for this purpose is likely to be formation specific but, given the extent of some targeted formations, evaluation could require a regional or even continental overview of a variety of aspects. Similar considerations apply to deep coal beds. The historical containment of oil and gas reserves is no guarantee of containment in the long-term since the integrity of such formations is generally compromise by large numbers of wells drilled into them, and by structural changes resultant from extraction of the hydrocarbon resources. All these considerations imply that such schemata will carry a long-term, trans-generational commitment to monitoring activities.

ii) Potential for leakage

The potential impacts associated with carbon dioxide in geological formations are largely associated with the possibility of leakage. It is possible that large scale release of gaseous carbon dioxide from formations used for CO_2 storage could take place with associated mortality of humans and their livestock (see: information on Lake Nyos above). The potential for such leakage will depend upon caprock integrity and the security of well capping methods in the longer term together with the degree to which the CO_2 is eventually ‘trapped’ through solubility in *e.g.* residual oil, formation waters or by reaction with formation minerals to form carbonates. As noted by Bruant *et al.* (2002) even in formations with adequate nominal capacity some of the injected CO_2 is expected to leak as a result of the buoyancy of the separate phase carbon dioxide, the induced pressure gradients from the injection and the variable nature of strata acting as barriers to upward migration. In addition it is possible that the reaction of CO_2 with reservoir minerals could affect permeability and porosity. Accordingly, CO_2 leaking from storage formations could intercept aquifers, surface waters and the land surface.

iii) Potential impacts

Leaks from natural CO_2 reservoirs and their impacts have been documented. Bruant *et al.* describe the surface impacts of leakage of magmatic CO_2 at Mammoth Mountain in the U.S. In addition to early stage human asphyxia, large areas of trees have died off as a result of high soil CO_2 concentrations. No additional lethal agents have been detected in this natural analogue. In the case of anthropgenically stored CO_2 the possibility of co-stored materials such as nitrogen and sulphur oxides leaking also needs to be taken into account.

One aspect of potential environmental impact that has received little attention is that likely upon sub-soil ecosystems. Although surficial terrestrial systems have been extensively researched in terms of their microbial ecology and the way in which this relates to other soil organisms, far less work has been carried out to investigate deep, sub-soil microbial communities and the wider ecological interactions which they may have. Given the possible biomass of these communities (based simply upon the sheer volume of habitat which they have available to occupy), this seems a substantial indeterminacy. Recent work (Cowen *et al.* 2003) has shown that a diverse (though relatively low biomass) microflora exists in the ocean basin crust consisting of organisms related to known nitrate and sulphate reducers together with heterotrophic organisms. Other work suggests that deep subsurface microbial systems are defined by heterogeneous physico-chemical conditions in subsurface environments (see: Brockman and Murray 1997) and that microbial life is widespread within the whole depth of the earth's crust including extreme temperature systems (see: Vorobyova *et al.* 1997). The overall functions of these deep microbial communities are unknown and the subject of considerable debate (Kerr 2002). Impacts upon these ecosystems due to CO_2 storage could be substantial but the consequences largely unknown.

iv) Research Needs

Research needs related to terrestrial geological formations are largely site specific in nature although designed to address concerns which are generic in nature. Broadly, these research needs attach to the issue of long-term containment and the consequences of containment failure. These include:

- Identification and characterization of natural analogues
- Site specific assessments of storage formation integrity
- Assessment of potential leakage pathways through fractures/porous media
- Potential impact on water resources, surface ecosystems
- Potential for solubility/mineral trapping and impacts on formation porosity
- Potential for catastrophic release
- Monitoring and remediation methods
- Development of geophysical monitoring techniques
- Characterisation of soil micro-organisms and potential ecological impacts
- Evaluation of impacts due to co-recovered acids gases and other contaminants

Conclusion

The portfolio of research needs associated with all forms of carbon storage is extensive. The potential impacts of carbon dioxide storage differ both qualitatively and quantitatively depending upon whether the storage is unconfined in deep ocean systems or in the constrained environment of sub-seabed or terrestrial geological formations. In addition, the impacts of ocean storage are likely to depend on whether the CO_2 is injected into intermediate depth waters, or introduced to form a lake bounded by clathrate. In the case of geological formations, the storage of CO_2 will differ according to the relative importance of solubility and mineral trapping as opposed to simple containment of unchanged liquid $CO_{2.}$

The differing research agendas implied by the different storage schemata reflect different states of knowledge. Fundamental questions as to the character of deep ocean systems and likely impacts of CO_2 storage on them need to be resolved, whereas the research needs attached to geological options tend to be more targeted at site specific issues.

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Legal and policy aspects: impact on the development of CO_2 storage

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Abstract

CO_2 capture and storage (CCS) is a climate change mitigation option. CCS, however, has a unique position in this mitigation context. An attempt to interpret the context and position of CCS is used to explain this unique position. It is concluded that CCS has a specific combination of 'challenges' in three domains: economy, (technical and institutional) infrastructure and support. The economy challenge is the best known and best documented of the three and will be described in another paper in this volume. This paper tries to address the other two challenges in a descriptive way (a survey of what is known at this moment). The infrastructure challenge is limited to legislation. Present legislation has been designed in a situation in which CCS did not exist. This legislation has a lot of 'opportunities' to be a show-stopper for CCS. Support for CCS is not yet clear, although the arrangement of the issues (what is an important aspect and what is not?) seems to settle down. These results can only be qualified as observations: the interaction of CCS with legal instruments has just begun and scientific research is very scarce in both areas.

Introduction: context and position of CCS

The logic behind tackling the climate change problem is simple: stabilisation means zero (net) greenhouse gas emissions. Such a 'zero emission' state will not be a single technical fix or blueprint nor will it be solely determined by socio-economic parameters, as can be seen from the wide variety of competing scenarios created to fulfil the stabilisation goal[7]. In recent publications and presentations the general conclusion seems to converge to a single message: 'there is no magic bullet and we will need every presently known technology to address the issue', or put it more actively: 'the answer is portfolio management'[8]. Since about 1995 CCS has been included in some scenarios, since about 2000 most scenarios have a CCS component. One could thus say that CCS is a component of 'the' portfolio. Nevertheless, reality is not that simple. Within the set of mitigation options CCS has a specific position. This distinctiveness will be described by positioning CCS in the following interconnected domains: economy, (technical and institutional) infrastructure and support.

Economy

CCS is most effective and efficient when it is used as a large-scale option. To inject, the minimum you need is one well and one compressor, you need some piping and a CO_2 capture facility. These technologies do not scale linearly: very high cost per ton of CO_2 for small quantities, moderate to low for large quantities[9]. CCS needs large investments due to the large scale and also has substantial running cost: electricity or gas for the compressors and O&M cost. Next to that, the possibilities for financial benefits for CCS are not very large:

- there are direct revenues for Enhanced Oil Recovery (EOR) or Enhanced Coalbed Methane (ECBM);
- there are no direct revenues for injection into deep saline aquifers (except for some countries where one can prevent fiscal payments for CO_2 emissions);
- there are no direct other (macro) economic advantages for CCS (except that it has some advantages in preparing a 'hydrogen economy' and helps to improve energy security in a climate constrained world).

This combination of factors does not make CCS a general attractive option. It also distinguishes CCS from other mitigation options that do not have all those disadvantages.

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[7] See for instance ref 20. Especially chapter 2 which also includes reference to other scenario studies.

[8] See some of the policy papers (especially the IEA presentation by Pershing) in ref 9.

[9] In the two project proposals in the Netherlands for C_{O2} storage (CRUST), one can observe a large scale-dependency for the costs of storing CO_2 (see www.crust.nl).

Infrastructure (institutional and technical)
CCS will very likely question the role CO_2 plays in society. In present society most of the CO_2 is released from stacks, and therefore, CO_2 will probably be considered as a waste stream. However, this CO_2 can be sold (for EOR or ECBM or to the greenhouse horticulture) and it is a commodity as well. In the case of emission trading, CO_2 is also a means of exchange. Therefore, if one takes CCS seriously on the organisational side, one has to reconsider a couple of formerly simple ideas: what is a waste stream? what is a commodity? what is a means of exchange? Consequently, present legislation is not yet adapted to the use of CCS.

CCS also challenges the way governments have created their financial support schemes for environmental beneficiary technologies. Most schemes are created to support a production technology (e.g. electricity production by PV modules) but they are not built to directly support CO_2 emission reduction. The introduction of CCS asks for an innovation in policy instruments. The introduction of a scheme for emission trading could be such an innovation.

On the physical side, the effective use of CCS will result in some form of pipe transport, whether or not accompanied by a hydrogen infrastructure. Therefore, CCS will also lead to reconsidering or redesigning the physical infrastructure. Redesigning can lead to substantial (macro) economic expenses.

In short: CCS will not be an easy fit in present society, on the organisational as well as the physical side.

Support
The ‘support position’ of a technology is the description of the way and the strength of support for a technology by different social actors. The support position should at least contain the description of the position of three groups of actors: industries, governments and citizens (or environmental NGOs acting as representatives of this group). Does the support position of a technology matter? Yes, and in more than one way. From research in social psychology can be deduced that there is a strong connection between the messenger and the reception of the message (e.g. ref 6 and 27). The authors themselves have experienced that it does make a difference which actor promotes the technology: the NGOs react, for instance, different to a CCS plan from government than to a CCS plan from industry. The support position can also influence the development of a technology. It could induce but it could also minimize conflicts: in the case of nuclear energy, government had shown to be an uncritical proponent, a position that induced conflict because the ‘citizens’ did not trust government anymore. In the case of CCS, the support position is not clear.

Impact of this distinctive position
The workers in the CCS area will endorse that it does feel like being in a vicious circle: ‘CCS will be taken seriously if the climate change problem is taken seriously, the climate change problem can be taken seriously if CCS is part of the portfolio’. The explanation given above shows that this feeling does reflect reality. It is caused by the fact that CCS has a unique position in the climate change mitigation context: there is a specific combination of ‘challenges’ in all three domains. Meeting those challenges will certainly influence the development of CCS.

Quality and structure of the paper
This paper will be dedicated to legislation and support. The actual interaction of CCS with society started only recently. Scientific research, on the other hand, is very scarce in that area. Therefore, the authors would like to stress that this paper is meant to prudently summarize what is said around the world about the subjects of legislation and support. The reader is asked to read the following text as a first, empirical and descriptive, survey. A lot of ‘experiences’ and ‘research’ has to follow to be able to speak of reliable and scientific knowledge.

Describing the discussions around the legal aspects of CCS is expected to expose the most important elements of the challenge in the area of ‘institutional infrastructure’. Therefore, section 2 will be limited to, and focused on, legislation. Section 3 will address the subject of support. The paper will be wound up with some concluding remarks.

Legislation

The discussions about the legal aspects of CCS started halfway the nineties and were centred on ocean storage until about 2000. In that year the CO_2 Capture Project (=CCP) started and the Netherlands started to work on the Buffer project, which nowadays is called CRUST. These two activities needed a proper interpretation of the effect of the existing legislation on the realisation of their projects. A couple of studies were carried out for geological storage in general and the on-shore variant in particular. The ocean discussion has already had a couple of rounds. The general discussion has just started and is more country specific. In Europe, the situation is somewhat more complex: there are a couple of directives (i.e. a European form of legislation) that can influence the ability of countries to make laws for CCS. Below is described what is known so far in three areas: international law, European directives and national legislation. Also a section is devoted to the relation between legislation and monitoring/verification.

International law

The 'ocean' related discussion centres around the Convention on the Prevention of Marine Pollution by Dumping Wastes and other Matter of 1972, mostly called the 'London Convention' (including the 1996 Protocol to this Convention). There are some related conventions: the UN Convention on the Law of the Sea (UNCLOS), the Paris Convention, OSPAR and the North Sea Conference. A couple of overviews are already produced (e.g. ref. 5, 11 and an especially extensive one: 15) and will not be reproduced here. The main issue is whether CO_2 storage falls under the jurisdiction of the treaties or conventions. If so, and if one sticks to the verbatim texts, the conclusion will probably be that CCS is not allowed in 'the' marine environment as protected in the conventions (see e.g. 15 and 17).

Other, more specific, questions are:

- Should CO_2 be classified as an industrial waste?
- Which body has or should have jurisdiction?
- What are the practical consequences of that possible jurisdiction?
- Where does the ocean/sea end and the deep underground begin?
- Whose is the CO_2 once it is stored?

That this is not mere discussion alone, is shown by the media attack of Greenpeace about an ocean storage plan in Norway, in which they claim that the plan 'of ocean dumping threatens international law' (press release of Greenpeace Norway, July 9th, 2002). One can learn from the overviews and discussions that nothing is clear yet, that there is no consensus about the answers to the main questions, but also that the treaties can become a show-stopper for CCS (in marine environments).

European directives

There are a couple of directives that can influence national legislation with respect to CCS: the framework directive on waste materials (75/442/EEG), the directive on dumping of waste materials (1999/31/EG), and the framework directive on water (2000/60/EG)[10]. If a certain material or a certain process falls under the jurisdiction of a directive, this means it falls under the jurisdiction of the national implementation of the directive (mostly a law) including all the rules, definitions, and so on, of the directive. In practice, this will mean extra legal activities and sometimes even (nearly) conflicting rules.

In the Dutch case, a legal taskforce has more or less sorted out the consequences of these directives for CO_2 storage 21. In the present situation, with the very strict jurisprudence on waste of the European Court in mind, they concluded that CO_2 falls under the jurisdiction of the directive of waste materials, but it is not a dangerous waste material. They also concluded that injection of CO_2 in the deep underground does not fall under the jurisdiction of the directive on dumping of waste materials. In that study (21) one can also observe that the present directives are designed in a situation in which CCS did not exist and it is not obvious whether CCS falls under the jurisdiction of the directives. Based on jurisprudence and other (legal) lines of arguments one can achieve a (!) plausible conclusion. As far as can be observed, specific legislation of CCS is not an issue that is already addressed by the European Commission or by the European Council of Ministers. This means that the discussion about interpretation of the directives will be carried out in national contexts. It is not clear that the outcome will be the same in each EU country. This situation can thus lead to diverging (legal) practices.

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[10] For an extensive description of EU directives, their content and their relevance: see ref 15.

National legislation

National legislation is too diverse to describe in this paper. The bibliography contains papers that describe the position in the US and in the Netherlands (especially refs 1, 11, 21, 26 and 28). Below some general observations are summarised:

- CCS is not yet included in national legislation; if CCS is related to an existing practice (e.g. EOR) the legal position is more clear;
- (very likely) an environmental impact assessment should be carried out for a CCS project;
- CCS is a new technology with its own risks; in some cases, one has to prove that no 'irreparable harm' will result and that CCS is necessary which can mean that one has to prove that 'no other reasonable alternatives are available'(see e.g. 11, pp 4-5);
- a CCS project will have to deal with a large variety of 'official' bodies: from federal to local, from government to interest groups (see e.g. 26);
- a CCS project mostly has two parts: above ground and underground; the part above the ground can very likely be covered with present legislation (with focus on controlling safety, see 1).

Monitoring and verification

CCS is justified by managing (or mitigating) the risks of climate change. Therefore, managing the risks of a CCS project should be the core business of the CCS operator. The major challenge for that core business is creating a reliable process for monitoring and verification. The technical aspects of these issues will be presented in other papers to this volume. In the context of legislation, reliable monitoring is an essential first step towards 'earning' a licence to operate. In case of a role for CCS in emission trading, the issue of verification becomes (even more) important.

Concluding remarks

In general one can conclude that the legal position of CCS is not clear, at this very moment, and there is no consensus about answers to key questions (like: is CO_2 a waste? Whose is the CO_2 and for how long?). The international treaties aimed to protect the marine environment will, however, very likely prohibit CCS in its area. Another aspect of legislation is the possibility of controlling or maintaining the permits. Apart from the other (technical) aspects of monitoring, this aspect alone justifies that reliable monitoring will become important.

Support[11]

This section will aim at describing the present state of 'knowledge' in the area of support. It should be a good starting point for those who want to study the subject and want to know what has been carried out until now. It is not intended to give 'the in depth analysis' of the support of CCS. The present knowledge in this area can not yet be called scientifically reliable: it is still in its infancy and can better be characterised by a basket full of observations. The next two paragraphs describe activities that took place that have a relation to support: the first about the Dutch experience, the second about other experiences. The third paragraph is about ongoing and future plans. After describing the activities, a first attempt to summarise the observations is made. The section is closed with some concluding remarks.

Experience in the Netherlands

The Netherlands Ministry of Environment prepared a project proposal for CO_2 use and storage in the Netherlands in 1997. Part of that project was framing a 'declaration of intent' with all actors involved: industry, greenhouse horticulture, local authorities and environmental NGOs. That part of the proposal was successfully finalised. However, the Dutch government cancelled the project itself and the declaration will thus remain confidential. What was learned in that process was input for a public debate about CCS in December 1998 and the outcome was a confirmation of what already was learned[12]. In the preparation of a paper for the GHGT-5 conference in Cairns in 2000, the authors carried out a non-representative survey among a couple of key-actors. The task of the actors was to prioritise arguments pro and contra CCS 23. In 2001, No-

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[11] The word 'support' is chosen because it better reflects the real problems of controversial climate change mitigation options than the phrase 'public acceptance'. Support is intended to include positions of all actors, while 'public acceptance' is mostly used to address the position of citizens (or voters or consumers) only. Neglecting the other actors will most likely lead to an unbalanced analysis of the implementation process.

[12] The background document for this debate is ref 3, the report of the debate is ref 4.

vem organised an informal meeting between scientists and NGOs, in order to revitalise the experience about perceptions of CCS[13]. This meeting did not lead to new insight. In 2002, a process was started to realise the CRUST project. This process also contains consultation activities 8. The oil and gas industry has created a platform with government and NGOs to discuss the problems for this sector[14]. The secretariat of this platform has produced a report in which CCS is also addressed 25.

Other experiences
The IEA Greenhouse Gas programme (IEA-GHG) facilitated a couple of workshops (forums) on Ocean Storage 12. Those workshops were spread over the world: New York, Kyoto and London. The participants of the workshops included scientists, government officials and representatives from NGOs, industry and students. Greenpeace also published a own report on CCS in 1999 16. In the same time, Bill Clewes interviewed some officials in the UNFCCC field about their perception of CCS 7. This work was commissioned by IEA-GHG in order to come to an effective communication strategy. CO_2 NET organised a seminar in September 2001 on agenda setting 13. Additionally, the CO_2 Capture Project joint industry project engaged the North American environmental NGOs in October, 2000, and the East of Atlantic environmental NGOs in June of 2001. Some of them were neutral to moderately positive. Most remarkable is that a half dozen of them in North America are interested in continuing the dialog and are willing to devote their time. IEA-GHG just released a paper about ‘Broadening the dialogue on CCS’ 14. Last but not least, a report on public opinion was published by the Tyndall Centre 10.

Plans for the near future
A couple of initiatives have already started or will start in the near future. In the European GESTCO project a public hearing is (still) planned for early 2003. CAN Europe has started a study which aims in exposing sufficient information for the members to come to well informed strategic position. In the Netherlands, a research project about the ‘implementation of clean fossil fuels’ has started in 2001. An important part of that research project is formed by carrying out a large enquiry (Information-and-Choice Questionnaire = ICQ) among a representative group of citizens. That ICQ is scheduled for 2003. The Tyndale Centre for Climate Change in the UK is planning to start an integrated project reviewing (geological) CCS and within that study they will undertake a review of public perceptions (partly funded by the UK DTI).

A first summary of observations
A number of more or less robust observations can be deduced from present reports and experiences. They will be categorised by theme:

1. **Public perception**: In general, we observe a negative attitude towards CCS by people who are confronted with the idea for the first time (and in a situation in which no direct relation with the climate problem at large is made): they perceive it as a high risky end-of-pipe technology (as is also expressed by Keith 19); In a situation where more is known about the context and the technology, the attitude is neutral or moderately positive: CCS is seen as an acceptable mitigation option in the context of a bridging policy (see the Tyndall report 10 and the priority setting in our paper 23).
2. **Budget allocation and bridging**: There still is a lot of worry about allocation of (government) budgets. Most actors are afraid that paying attention to CCS will divert from developing other necessary energy strategies (efficiency improvement, energy savings, renewable energy sources). If CCS is presented as part of a bridging strategy toward a sustainable energy supply, the attitude becomes more positive (see 10 and 23).
3. **Concerns about CCS**: The major concerns about the technology of CCS is similar in all studies: safety of storage (integrity of the reservoir, seismic activity, etc.) and ‘containment’ (there should be ‘a visible barrier to prevent CO_2 escaping’, 10, p. 11). These concerns are the main reasons why storage in empty oil or gas fields draws more support than storage in aquifers without proven cap rock. The key questions seem to be: what are the risks of leakage to the environment and potential adverse impacts on life and human life and what are acceptable leakage rates. The oceans draw other concerns: they are seen to be very sensitive biological resources that most people don't want to see meddled with.
4. **Industrial actors or fossil energy in general**: There is certainly a great variety of opinions on CCS in the industry. The oil- and gas industry appears to be more interested than the

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[13] Only a confidential report of the meeting exists.
[14] Consultation Body Oil and Gas (Overlegorgaan Olie en Gas; OOG) chaired by Prof. Peeters.

power industry. Part of that variety can be explained by the relevance of CCS to the core business of certain companies but also by less tangible aspects: the attitude of a company towards the climate change problem, the uncertainty about economic perspectives of CCS, and the fear of 'public condemnation for doing something in the public interest' (backfiring). The possibility of backfiring is underlined by an observed negative perception of industry by 'the' public: in the Tyndall report one reports that part of the focus group was 'highly suspicious of the motivations of large corporations' (10, p.8). Even the bad reputation of fossil energy in general is part of this complex part of the support position of CCS.

Concluding remarks

A first tentative conclusion could be that these observations show that adequate support can be achieved by a serious and all-embracing approach to a sustainable energy supply. This conclusion and the observations of the preceding paragraph could (at their very best) be qualified as hypotheses that should be (re)studied in future research. The studies mentioned earlier (§3.3) will very likely lead to a more complete picture about support and will lead to results within the next two years. One should aim at incorporating these results in the proposed IPCC report.

Conclusion

Support and infrastructure (legislation) will very likely play an essential role in the development and implementation of CCS. One can even discern a couple of show-stopping elements. Therefore, the impact of legal and policy issues can be huge. The real and actual interaction between CCS and society has just started. Therefore, scientific knowledge about legal and support issues is still in its infancy.

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Decarbonized fossil energy carriers and their energy technology competitors

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Abstract

Stabilizing atmospheric CO_2 in the range 450-550 ppmv requires deep reductions in CO_2 emissions for both electricity generation and markets that use fuels directly. Fossil fuel decarbonization/CO_2 storage is an important option for reducing emissions from the power sector, but there are alternative non-carbon-based electricity options that will be strong competitors in terms of cost. Because of land-use constraints, use of carbon-neutral biofuels alone will be inadequate to solve the climate problem in markets that use fuels directly, so that it will probably also be necessary to introduce H_2 as an energy carrier. Costs for H_2 from fossil fuels with storage of the separated CO_2 are likely to be far less than costs of making H_2 from water using carbon-free (renewable or nuclear) electricity or heat sources. Although CO_2 capture and storage associated with making H_2 via gasification of coal and other carbonaceous feedstocks offers one of the least-costly approaches to a climate-friendly energy future, H_2 will not be widely used as an energy carrier for at least two decades. Nevertheless, thus making H_2 to serve industrial markets can provide low-cost CO_2 for CO_2 storage demonstration projects, thereby playing an important near-term role in understanding better the prospects for coping with climate change via decarbonizing fossil fuels and CO_2 storage.

Introduction

Avoiding 'dangerous anthropogenic interference' with the climate system might require stabilizing atmospheric CO_2 in the range 450 – 550 ppmv (O'Neill and Oppenheimer, 2002)—a daunting challenge in light of dependence on fossil fuels for energy and expectations of expanded energy demand as a result of population and economic growth. Achieving such a goal would require reducing CO_2 emissions from the energy system relative to a BAU[15] future (the IPCC's IS92a scenario) 30-65% by mid-century and 70-90% by 2100 (Hoffert et al., 1998).[16] The likelihood that society would pursue such a goal depends on costs.

Extracting energy from fossil fuels as H_2 or a H_2-rich gas, with storage in geological media of the CO_2 coproduct, is an important option for helping realize the needed deep reductions in CO_2 emissions at costs that are not so high as to discourage society from pursuing such a target. This paper explores this decarbonization/CO_2 storage strategy to provide both electricity and H_2 as the major energy carriers in a climate-constrained world and highlights the importance of ascertaining in the next decade or so if geological storage of CO_2 at large scales will be acceptable with regard to both climate change and local environmental risks. Emphasis is on costs of achieving deep reductions in emissions. Cost estimates reported from different studies have been adjusted to a common basis in order to make inter-study comparisons meaningful.[17]

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[15] The following are definitions of abbreviations and acronyms used in this paper:
BAU = business-as-usual
CAES = compressed air energy storage
CGCC = coal gasifier combined cycle
GDP = gross domestic product
GHG = greenhouse gas
HHV = higher heating value
ICE = internal combustion engine
LHV = lower heating value
MHR = modular helium reactor
MSW = municipal solid waste
NGCC = natural gas combined cycle
NIMBY = 'not in my back yard'
PEM = proton exchange membrane
SCS = supercritical steam (coal power)
UCS = ultra-critical steam (coal power)

[16] Key parameters that characterize IS92a as a BAU energy future are that during 1990-2100 population increases 2.1-fold, and GDP per capita and the energy intensity of the economy grow on average at the historical rates of + 1.6%/y and – 1.0%/y, respectively. Under IS92a, CO_2 emissions from fossil energy in 2100 are 19.8 Gt C/y and cumulative emissions, 1990-2100, are 1500 Gt C.

[17] Reported capital costs are total capital requirements (which include interest charges during construction); for all systems, an annual charge rate of 15%/y and an 80% capacity factor are assumed. For cases involving C_{O2} capture /storage, it is assumed that the CO_2 is transported 100 km in a single pipe to a site where the CO_2 is injected into a saline aquifer 2 km below ground for storage, with the storage cost (\$/t CO_2) calculated according to the model described in Ogden (2002). The base-case coal price is assumed to be \$1.17/GJ, the US average price for electric generators in 2000. Except where explicitly indicated otherwise, all energy values are HHVs.

Decarbonizing electricity generation

One way to decarbonize power generation is to recover CO_2 from power plant flue gases (post-combustion recovery), compress it to a supercritical state, transport it to a storage site, and inject it into appropriate geological media for storage. The energy efficiency and cost penalties are substantial, with most of the cost penalty associated with CO_2 capture (e.g., see the NGCC and coal SCS and UCS cases in Table 1). These penalties are high because of the low concentration/partial pressure of CO_2 in flue gases.

The CO_2 concentration/partial pressure in stack gases can be significantly increased and the CO_2 recovery cost reduced via burning fuel in O_2 instead of air—a so-called 'oxyfuel' strategy (Thambimuthu et al., 2003; Williams et al., 2000). However, the cost penalty can be reduced still further by shifting to pre-combustion strategies that involve CO_2 recovery at high concentration/partial pressure from the shifted synthesis gas of CGCC plants.[18] In this approach, coal is gasified to produce synthesis gas (mostly CO and H_2), which is cleaned, cooled and reacted with steam so that the CO is converted to H_2 and CO_2 at high concentration/partial pressure. Table 1 shows that although coal SCS, UCS, and CGCC plants produce electricity at comparable costs and efficiencies when CO_2 is vented, the CGCC option with CO_2 capture involves much lower energy and cost penalties than flue gas recovery options. Both CGCC and oxyfuel strategies require expensive O_2 plants, but for the CGCC option the O_2 required is only 1/3 as much as for the oxyfuel strategy (Williams et al., 2000). A further advantage of the CGCC approach is that essentially the same technology can be used to make H_2 from coal, as discussed below.

With the notable exception of an IEA GHG R&D Programme study (IEA GHG, 2000), most studies comparing alternative coal options (e.g, EPRI/DOE, 2000; David and Herzog, 2000; Williams et al., 2000) indicate that with CO_2 capture electricity costs would be less for CGCC plants than for coal steam-electric plants. However, even for the IEA GHG R&D Programme study, the capital cost and energy penalties are significantly less for the CGCC option than for the coal steam-electric option; the main reason the IEA GHG generation cost estimate for the CGCC option is higher is a higher cost estimate for the CGCC with CO_2 vented (see, e.g., Thambimuthu et al., 2003). Such variation among studies for CGCC cost estimates are understandable because the technology is relatively new. Cost reductions, as well as a convergence of cost estimates, can be expected for CGCC technology as experience grows and the technology improves. Although very few CGCC plants have been built to date, experience with gasification technology has been growing rapidly (mostly for chemical process and refinery applications)—with worldwide synthesis gas production capacity totaling ~ 60 GW_{th} at present and new capacity being at a rate ~ 3 GW_{th}/y (SFA Pacific, 2000).

Even if the CGCC proves to be the winning coal-electric option when CO_2 is captured and stored, the technology would have a hard time competing in a carbon-constrained world if natural gas is readily available. The natural gas price chosen for the NGCC in Table 1 is \$3.9/GJ[19]—the value at which generation costs are equal for the NGCC and the CGCC with CO_2 capture/storage in the presence of a carbon tax equal to the avoided cost for the CGCC (\$97/t C[20]). But at this carbon tax level it would not be worthwhile to capture/store CO_2 at the NGCC plant;[21] instead, the NGCC power generator would vent CO_2 and pay the carbon tax and would still be able to provide electricity at a cost less than 75% of the cost for the CGCC with CO_2 capture/storage. In the many parts of the world where natural gas prices are lower than \$3.9/GJ, the competition from NGCC plants would be more severe.

In order for the CGCC with CO_2 capture/storage to break even with the NGCC with CO_2 venting in the presence of a carbon tax sufficiently large to induce capture/storage for the CGCC option,

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[18] With current technologies there are no cost advantages for pre-combustion CO_2 capture options for NGCC plants.

[19] Such a natural gas price level might become typical for many large users during the course of the next two decades. For example, it is projected that in the United States the natural gas price for electric generators will rise from \$3.1/GJ in 2005 to \$4.1/GJ in 2020 (EIA, 2002).

[20] With such a tax in place, the costs for the CGCC options with CO_2 venting and capture/storage would be the same.

[21] The needed incentive is a carbon tax ~ \$310/t C (see Table 1).

the natural gas price would have to be ~ $6.0/GJ—a price level far in excess of natural gas prices in most parts of the world (see Figure 1).[22]

One possible near-term opportunity to reduce costs for CGCC with CO_2 capture/storage is to eliminate the sulfur recovery processes that are required for air-quality reasons with CO_2 venting. The same physical solvent used to separate CO_2 from shifted synthesis gas will also absorb H_2S (the main chemical form of sulfur in the synthesis-gas product of gasification). An alternative to separating out the H_2S and converting it to elemental sulfur (which would typically be done with CO_2 venting) is to dispose of H_2S in underground media along with CO_2. (Chiesa et al., 2003; Kreutz et al., 2003). It is not yet known if this 'co-storage' option would be safe enough to be routinely deployed.[23] If co-storage proves to be viable, this practice could reduce the carbon tax needed to induce capture/storage and the electricity cost at breakeven relative to the pure CO_2 storage case; however, the natural gas price would still have to be extraordinarily high to enable the CGCC with co-storage to compete with the NGCC with venting (see Figure 1).

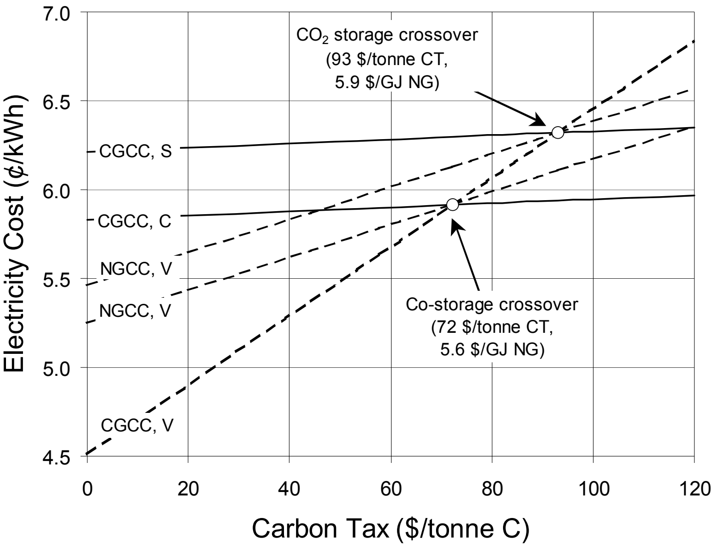

Figure 1: Electricity cost competition in climate-constrained world for: (i) coal gasification combined cycle (CGCC) plants with CO_2 vented (V), stored (S), or co-stored (C) with H_2S and (ii) natural gas combined cycle (NGCC) plants with CO_2 vented (V)

Assumptions:

(*i*) CCGC and NGCC plants as described in Table 1;

(*ii*) coal price = $1.17/GJ;

(*iii*) The equations $(P_E)_{NGCC,V} = (P_E)_{CGCC,S} = (P_E)_{CGCC,,V}$ equating electricity prices (P_E) determine assumed natural gas price (P_{NG} = $5.9/GJ, capture/storage case; P_{NG} = $5.6/GJ, capture/co-storage case) as well as the least carbon tax ($93/t C, storage case; $72/t C, co-storage case) at which storage or co-storage is cost-justified. At natural gas prices lower than those at the indicated CO_2 storage or co-storage points (open circles), the CGCC, C can compete with the NGCC,V only at higher carbon taxes.

Source: Chiesa et al. (2003) and Kreutz et al. (2003).

Renewables, especially wind power, will also offer competition. In particular, baseload power from wind/CAES systems would typically be less costly at today's typical wind power costs ~ 5 ¢/kWh (BTM Consult, 1999), because baseloading wind power with CAES units typically adds less than 1 ¢/kWh to the generation cost (Cavallo, 1995; Lew et al., 1998; Williams, 2002). Moreover, wind power costs might fall to the range 3.0 ¢/kWh or less by 2020 (Turkenburg et al., 2000; IPCC, 2001;Williams, 2002). If such low costs can be realized, baseload wind/CAES

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[22] The calculations presented in Figure 1 are for estimated CGCC performance and cost (43.5% efficiency and $1347/kW$_e$ with CO_2 venting; 36.9% efficiency and $1748/kW$_e$ with CO_2 capture) different from those estimated in Table 1 (although the performance and cost estimates for the NGCC are the same in both cases). As a result the carbon tax needed to induce capture/storage for CGCC technology is $93/t C rather than the $97/t C value indicated in Table 1, and the breakeven natural gas price is $5.9/GJ compared to $6.5/GJ for the CGCC performance and cost estimates of Table 1.

[23] However, there are many relatively small-scale projects in Canada where mixtures of H_2S and CO_2 recovered from 'sour' natural gas in a wide range of relative concentrations are disposed of underground in depleted oil and gas fields and deep aquifers as the least-costly approach for reducing sulfur emissions in response to regulatory requirements relating to such emissions (Williams, 2003).

power derived from large wind farms in remote areas would be roughly competitive with NGCC power and could often be transmitted cost-effectively via high-voltage transmission lines to major electricity markets—thereby advancing wind to the status of a major competitor in many power markets, owing to the vastness of high-quality remote wind resources in various parts of the world (Rogner et al., 2000; Turkenburg et al., 2000; IPCC, 2001; Williams, 2002).

What are the prospects for improving CGCC—arguably the most promising power option for coal in a carbon-constrained world? Many studies project that CGCC costs will fall with experience and continuing technological improvements (e.g., David and Herzog, 2000; de Puy et al., 1999). However, when the natural gas price and carbon tax are \$4/GJ and \$93/t C, respectively, the capital cost with capture/storage would have to be reduced to ~ \$1250/kW$_e$ to enable the CGCC to compete with the NGCC with venting—a daunting challenge.

One way to reduce CGCC generation costs with capture/storage while awaiting technological advances is to exploit opportunities for enhanced resource recovery (e.g., enhanced oil recovery or enhanced coal bed methane recovery) using the recovered CO_2. Such possibilities were neglected in the calculations presented in Table 1 and Figure 1. In the early years of an energy economy that involves geological storage of CO_2, enhanced resource recovery options would tend to be the norm (Williams et al., 2000; Gale, 2003; Wildenborg and ven der Meer, 2003).

Also, with a strong climate-change mitigation policy in place, natural gas prices would probably rise significantly, because natural gas demand would grow more rapidly than under BAU conditions (at the expense of the more carbon-intensive coal), even though total energy demand would grow more slowly than without such a policy.

The need to decarbonize fuels used directly as well as electricity

Solving the carbon problem only for electricity will fall far short of solving it for total energy. Consider that in fuels used directly (i.e., other than for making stationary power) accounted for 69% of global CO_2 emissions in 1997—a percentage that is not likely to decrease much, despite the global trend toward increasing electrification of the energy economy, because even under BAU conditions the trend in the power sector is expected to be increasing contributions from zero- and low-carbon power sources.[24]

The importance of H_2 for markets that use fuels directly

The options for realizing near-zero emissions in markets that use fuels directly are shifting to biomass-derived fuels and/or to H_2 that is produced without releasing CO_2.

Biomass can be converted to clean fuels for transportation and other applications by various routes, including biological processes (e.g., ethanol from woody biomass via enzymatic hydrolysis) and by the synthesis gas route (e.g, methanol, synthetic middle distillates, or dimethyl ether). The growing of biomass on a sustainable basis leads to no net buildup of CO_2 in the atmosphere, because CO_2 released in combustion is balanced by CO_2 extracted from the atmosphere during photosynthesis. Biomass-derived energy can be provided from residues of agricultural and forest product production and from biomass grown on plantations dedicated to growing biomass for energy. Modern clean fluid fuels derived from biomass are likely to play major roles in markets that use fuels directly (WG II of IPCC, 1996; Johansson et al., 1996), especially in countries that have large potentially available land areas suitable for growing energy crops (e.g., Brazil, United States). But if primary energy demand increases 3-4X in this century, as suggested by IS92a and many other long-term forecasts, biomass supplies alone are not likely to enable solving the carbon problem for fuels used directly. Analysis carried out for the World Energy Assessment concluded that the practical global potential for biomass production for energy (residues plus plantation biomass) over the long-term is 100-300 EJ/y (Turkenburg et al., 2000). This suggests that the biomass energy option offers only a modest potential to improve upon IS92a in terms of greenhouse gas emissions from energy over the longer term, because that scenario already involves, for 2050, the use of 128 EJ/y of biomass (compared to 655 EJ/y of fossil fuels) and, for 2100, 205 EJ/y (compared to 865 EJ/y of fossil fuels) (Williams, 2003).

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[24] For example, the IPCC's IS92a scenario projects that fuels used directly will account for 75% of total CO_2 emissions by 2100, when total emissions would be 20 Gt C/y (Williams, 2003).

Thus, solving the carbon problem for fuels used directly probably requires introducing H_2 as an energy carrier.

Comparing fossil fuel, renewable, and nuclear primary energy options for H_2 manufacture

Though H_2 is not yet used as an energy carrier, H_2 production technology is well established worldwide for applications in the chemical process and petroleum refinery industries. According to the US Department of Energy, it is currently produced at a rate of 400 billion Nm^3/y or ~ 5 EJ/y, equivalent to more than 1% of global primary (Dunn, 2001).

Hydrogen from fossil fuels. Where natural gas is readily available, H_2 via steam reforming of natural gas is often the least costly option for making H_2 today. At a natural gas price of $3/GJ that is typical for large industrial and electric power industry consumers in many parts of the world today, H_2 can be produced in large (1 GW_{H2}) plants at a cost of $5.5/GJ (81% efficiency), with CO_2 vented at a rate of 17.5 kgC/GJ; with CO_2 captured/stored (so that emissions are reduced to 2.7 kgC/GJ), the cost increases to $7.2/GJ (78% efficiency) (Williams, 2003). More than half of the total cost is accounted for by the natural gas input. Notably, with transportation applications in mind, the cost with capture/storage is $0.27/liter of gasoline-equivalent energy (LHV basis)—8% higher than the US average refinery gate price of gasoline in 2000.

H_2 can also be made from coal via gasification—in a process very similar to that for decarbonizing electricity generation via CGCC (70.3% efficiency, CO_2 vented; 67.7% efficiency, CO_2 capture/storage—Chiesa et al., 2003; Kreutz et al., 2003). As for the CGCC with CO_2 capture, the CO_2 coproduct can be either stored in a relatively pure form or co-stored along with H_2S at lower cost. Interest in coal stems from its abundance and relatively low cost compared to natural gas. The conversion technology is well-established in the market; in China there are at least 16 projects using modern gasifiers that produce H_2 via gasification of coal and petroleum residues as an intermediate product in the manufacture of ammonia for fertilizer (SFA Pacific, 2000).

Figure 2 presents cost estimates for H_2 both from natural gas via steam reforming (1 GW_{H2} scale)[25] and from high-sulfur coal via gasification (@ 1.2 GW_{H2}) in the presence of a carbon tax and two alternative assumed natural gas prices ($4.1 and $3.9/GJ).[26] The curves associated with a $4.1/GJ natural gas price are for coal H_2 technology involving storage of pure CO_2 when CO_2 is captured; the curves associated with the lower natural gas price involve coal H_2 technology for which H_2S is recovered and co-stored underground along with CO_2 when CO_2 is captured. In either case it is assumed that the natural gas price is at a level such that the cost of H_2 from natural gas with CO_2 vented equals the cost of H_2 from coal with CO_2 captured and stored or co-stored in the presence of the minimum carbon tax needed make H_2 with CO_2 captured and stored or co-stored competitive with coal-derived H_2 when CO_2 is vented.

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[25] See Williams (2003), based on Foster-Wheeler (1996).

[26] The natural gas price affects coal H_2 costs slightly because the process considered involves producing a small amount of electricity as a coproduct of H_2 manufacture, and, in this set of calculations, it is assumed that this electricity is worth the cost of making electricity in a NGCC with CO_2 vented (assuming the NGCC technology described in Table 1).

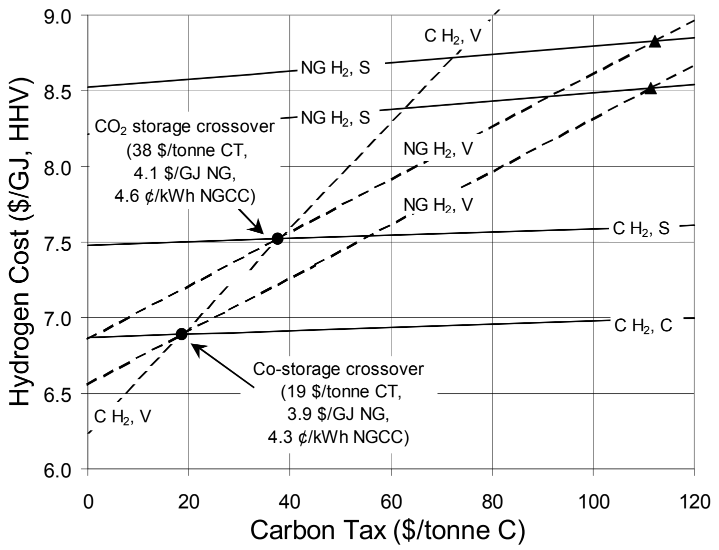

Figure 2: Cost competition in climate-constrained world for hydrogen derived from natural gas (NG H_2) and coal (C H_2)—with CO_2 vented (V), captured/stored (S), or captured/co-stored (C) with H_2S
Assumptions:
(*i*) hydrogen plants as described in main text;
(*ii*) coal price = $1.17/GJ;
(*iii*) The equations $(P_{H2})_{NG,V} = (P_{H2})_{Coal,S} = (P_{H2})_{Coal,V}$ equating H_2 prices (P_{H2}) determine assumed natural gas price (P_{NG} = $4.1/GJ, storage case; P_{NG} = $3.9/GJ, co-storage case) and associated NGCC, V electricity prices at which the electricity coproduct of C H_2 is valued) as well as the least carbon tax ($37/t C, storage case; $18/t C, co-storage case) at which storage is cost-justified). At natural gas prices lower than those at the indicated storage or co-storage points (closed circles) H_2 from coal with storage or co-storage can compete with H_2 from NG with venting only with higher carbon taxes. The closed triangles indicate the carbon tax levels at which the storage or co-storage option becomes competitive for NG-derived H_2.
Source: Chiesa et al. (2003) and Kreutz et al. (2003).

Several conclusions can be drawn from Figure 2 and the underlying analysis. *First*, costs for coal-derived H_2 when the carbon tax is the minimum needed to induce CO_2 capture/storage or capture/co-storage ($6.9/GJ to $7.5/GJ) are comparable to the cost of H_2 from natural gas with capture/storage when natural gas is priced at $3/GJ (see above discussion) and less than the cost of H_2 from natural gas with capture/storage when the natural gas price is $4/GJ. *Second*, the cost penalty for CO_2 capture/storage is comparable (in $/GJ) for the coal and natural gas cases, despite a CO_2 disposal rate (in kg CO_2/GJ) that is twice as large with coal.[27] *Third*, the cost of coal-derived H_2, which involves a capital-intensive manufacturing process, is relatively insensitive to the coal price: increasing the coal price 70% from the assumed value to $2/GJ increases the H_2 cost only 16%. *Fourth*, the carbon tax needed to induce CO_2 capture/storage is much less for H_2 manufacture than for electricity generation (compare Figures 2 and 1)—largely a result of the fact that in the H_2 case, in contrast to the electricity case, water gas shift reactors and gas separation equipment are needed even if the CO_2 is vented so that extra gas processing requirements are less with H_2 when a shift is made from CO_2 venting to CO_2 capture. *Fifth*, if co-storage proves to be viable, this practice might typically reduce the carbon tax needed to induce capture/storage by half and reduce the cost of H_2 at the breakeven tax by about 10% relative to the pure CO_2 storage case.

Costs presented in Figure 2 are for H_2 containing very low levels of CO. Low CO levels are desirable when H_2 is used in low-temperature proton-exchange-membrane fuel cells[28]—the current favored fuel cell technology for automotive applications (Burns et al., 2002; Ogden et al., 2003). However, for combustion applications (e.g, thermal power generation, space heat and process heat generation, cooking) high H_2 purity is not so important. For such applications the final step in the H_2 manufacturing process of H_2 purification (typically involving use of pressure-

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[27] This arises because in the coal case the CO_2 is removed at much higher partial pressure. Not only is the CO_2 fraction of the shifted synthesis gas much higher for coal than for natural gas, but also commercial gasifiers are available at 70 bar (assumed for the presented costs), whereas pressures for steam reformers are limited to 25-30 bar because of high heat transfer requirements through the reformer walls to drive the highly endothermic steam reforming reaction.

[28] For such fuel cells, the CO concentration in the H_2 must typically be no more than ~ 10 ppmv.

swing adsorption technology) can be eliminated. The resulting 'fuel-grade' H_2 that might contain ~ 1% CO would be 10-15% less costly to make than high purity H_2 (Kreutz et al., 2002, Chiesa et al., 2003; Kreutz et al., 2003).

Finally, although coal-derived H_2 production technology is established in the market, technological innovations can be expected[29] that might lead to lower costs than those presented here.

Electrolytic hydrogen. H_2 can also be derived electrolytically from water using a non-carbon-based source of electricity—renewable or nuclear. Plausibly baseload renewable (e.g., from a wind/CAES plant) or nuclear electricity might become available at a generation cost ~ 4 ¢/kWh, and electrolyzers might become available at half their current capital costs (Williams, 2003). But electrolytic H_2 would be about twice as costly as H_2 from coal with CO_2 carbon capture/storage (compare Table 3 and Figure 2). Breakeven with coal H_2 would require an implausibly low baseload electricity 'feedstock price' of 1.8 ¢/kWh. When first introduced as an energy carrier, H_2 might be produced using low-cost offpeak hydroelectric power, which would often be competitive (Ogden, 1999), and variable nuclear costs might plausibly become low enough to make H_2 from offpeak nuclear power competitive. However, offpeak electricity pricing strategies would be appropriate only where H_2 production is a minor activity, so that power generation could shoulder capital and other fixed charges. But in a climate-constrained world H_2 would eventually be required at levels in excess of the level of power generation (Williams, 2003), so that fixed charges would have to be allocated to H_2 production.

Hydrogen from water via complex thermochemical cycles. The water molecule can also be split using heat. If this were done directly, temperatures of the order of 4000 °C would be needed—which is not now feasible because of the absence of materials for containing the reactions. Over the years various multiple-step chemical processes have been proposed for making H_2 from water thermochemically at temperatures much lower than for this brute-force approach—using either nuclear heat [(e.g., heat that can be provided by a high-temperature helium gas-cooled reactor (Yoshida, 1983; Yalçin, 1989)] or high-temperature solar heat that could be provided with collectors that concentrate sunlight (Steinfeld and Palumbo, 2001). For such processes, water and heat are consumed, and both H_2 and O_2 are produced; the rest of the chemicals are recycled. Overall efficiencies for converting heat into H_2 that are ~ 50% (Yoshida, 1983).
Thermochemical processes for H_2 manufacture are far from being commercially available. A recent assessment (Brown *et al*., 2002) of 115 thermochemical cycles for making H_2 from a nuclear heat source and alternative reactor concepts for providing the needed heat singled out the sulfur-iodine (S-I) process[30] being developed in the United States (at General Atomics) as one of two processes warranting focused development, and (*ii*) the high-temperature helium gas-cooled reactor as the most promising reactor that could be commercialized over the next decade or so that would be suitable for use with these processes.

Table 2 presents an estimate of the cost of H_2 produced via the S-I process (1.2 GW_{H2} scale) for an estimated process efficiency of 50% in converting nuclear heat into H_2. This cost[31] is 80% higher than the cost of H_2 from coal with carbon capture/storage. There is probably not much room for reducing costs below these estimates both because there little potential for increasing efficiency [General Atomics researchers estimate that potential efficiencies are in the range 45-55% (Ken Schultz, private communication, April 2002)] and because the projected nuclear capital and O&M costs are quite optimistic relative to experience with light-water-reactor technology (Williams, 2003).

Hydrogen from biomass and MSW. H_2 can be produced from biomass (Williams et al., 1995) and municipal solid waste (MSW) (Larson et al., 1996) via gasification in much the same way as

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[29] Both continuing marginal technological improvements as well as radical innovations—e.g., H_2 separation membrane reactors for H_2/CO_2 separation (PI & TG, 2002; Kreutz et al., 2002) and oxygen ionic transport membranes as an alternative to cryogenic air separation for O_2 production (Kreutz et al., 2003)—can be expected.

[30] The S-I process is based on the following reactions aimed at decomposing water thermochemically:

$$H_2SO_4 \rightarrow H_2O + SO_2 + \tfrac{1}{2} O_2 \ (850\ ^{\circ}C),$$
$$2\ HI \rightarrow H_2 + I_2 \ (450\ ^{\circ}C),$$
$$2\ H_2O + I_2 + SO_2 \rightarrow H_2SO_4 + 2\ HI \ (120\ ^{\circ}C)$$

[31] The estimated costs for nuclear H_2, electricity, and heat presented in Table 2 are based on component cost estimates developed under the US DOE's Nuclear Energy Research Initiative (Brown *et al*., 2002; personal communication from Ken Schultz, General Atomics, April 2002).

it can be produced via gasification of coal. Biomass-derived H_2 might not be much more costly than coal-derived H_2 with capture/storage if biomass feedstock costs are moderate (~ \$2/GJ), though capital costs are uncertain, in large part because suitable gasifiers have been developed only to the demonstration level. Capital costs would be higher for MSW but levelized lifecycle costs for H_2 might be comparable to costs with biomass because feedstock costs are typically negative (MSW generators pay for its disposal—e.g., in landfills).

Even though the sustainable production and use of biomass energy is carbon neutral, the CO_2 coproduct of H_2 manufacture[32] might be captured and stored underground—in effect 'making room' in the atmosphere for coal[33] because CO_2 so stored was earlier extracted from the atmosphere during photosynthesis (Johansson et al., 1996; WG II of IPCC, 1996; Williams, 1998). *Photochemical hydrogen.* The long-term outlook for solar H_2 might not be as bleak as the above calculations for electrolytic H_2 suggest. Another way to harness solar energy for H_2 production is direct splitting of water via photochemical processes—e.g., using photon-absorbing semiconductors as electrodes in an electrolyte, producing H_2 at the cathode and O_2 at the anode. What is needed are cheap, stable electrodes that can absorb and use most of the photons in the solar spectrum in H_2 manufacture. Finding the right materials has been an elusive goal. The DOE benchmark for a commercially viable technology is 10% efficiency (Service, 2002). Until recently photochemical conversion efficiencies achieved in the laboratory have been about 1% (e.g., using n-type TiO_2 as electrode material). But Khan et al. (2002) report 8.5% efficiency using instead a chemically modified TiO_2 electrode material. This encouraging finding underscores the importance of R&D in this area, although commercial technology is in the distant future even if this finding holds up. And whether commercial technology would be significantly less costly than electrolytic H_2 remains to be determined.

Can H_2 compete in energy markets?

The challenges of and prospects for making H_2 viable as an energy carrier can be gleaned by considering, as illustrative examples, its use in two very different markets: automotive and industrial energy applications.

Hydrogen for cars: All of the world's major automakers are making huge investments to develop and commercialize H_2 fuel cell cars in 10-15 years time (Burns et al., 2002). Whether this ongoing technological race will lead to successful commercial products is uncertain.

The automobile is a difficult market for H_2, in part because current storage technology (compressed gaseous H_2 storage @ 350 bar or more) is characterized by a low volumetric energy density (~ 1/10 that of gasoline) and making H_2 available to consumers entails high costs. Although, as noted, the production cost of fossil-fuel-derived H_2 with CO_2 capture/storage is comparable to the refinery-gate price of gasoline on a gasoline-equivalent energy basis, the cost to the consumer at refuelling stations for H_2 powered cars would be about twice that of gasoline (see Table 4), with much of the cost increment over the production cost accounted for by the refuelling station, where costs are dominated by the capital and energy for H_2 compressors. Although cars powered by fuel cells (which require H_2 fuel) are the logical focus of automotive applications of H_2, fuel cell costs are presently too high by more than an order of magnitude.

Several considerations suggest these obstacles might be surmountable. *First*, acceptable range between refuelings (~ 500 km) appears to be feasible with vehicle redesign, even with current H_2 storage technology, because fuel cell cars are likely to be ~ 3X as fuel efficient as today's gasoline internal combustion engine (ICE) cars of comparable performance (but probably only ~ 2X as fuel-efficient as advanced ICE cars that might be the main competitors when fuel cell cars become commercial) (Ogden et al, 2003a). This fuel economy gain implies that the fuel cost per km would not be much higher than for the gasoline cars that fuel cell cars would be competing

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[32] For woody biomass the CO_2 storage rate is ~ 24 Mt C/EJ of H_2 (Williams, 1998), ~ 1/3 higher than the average CO_2 emission rate for fossil fuel burning.

[33] To illustrate this strategy's potential for climate-change mitigation, suppose that biomass energy in the long-term is produced at a rate of 300 EJ/y and is entirely converted to 206 EJ/y of H_2 with storage of the separated CO_2. The associated rate of extracting CO_2 from the atmosphere and storing it would be 4.9 Gt C/y. This stored CO_2 might be used to offset the CO_2 emissions associated with the production of 135 EJ/y of H_2 from coal for which the CO_2 coproduct is vented. In other words, the manufacture of H_2 from 300 EJ/y of biomass with CO_2 capture/storage would lead in this instance to the annual production of 335 EJ/y of H_2 with zero net CO_2 emissions.

with (see Table 4). *Second*, the current high vehicle costs are for cars produced 'one off.' Inherent materials and fabrication costs are not high for the currently favored proton exchange membrane (PEM) fuel cell, for which large reductions in cost are expected as a result of mass production at large scales and learning-by-doing (experience) effects. And *third*, a plausible case can be made that, if the external benefits offered by the fuel cell car (near zero lifecycle emissions of both air pollutants and greenhouse gases and enhanced energy supply security as a result of the shift from oil) are internalized in the lifecycle cost comparison, mass-produced H_2 fuel cell cars could become cost-competitive within 10-20 years—although valuations of these externalities are highly uncertain (Ogden et al., 2003a; 2003b).

Industrial energy: The potential industrial market for H_2 is significant and probably easier to develop than the automotive market. Consider, for illustrative purposes, that industry accounts for more than 1/3 of total US natural gas use. The gas consumption rate is 1.6 times as large as gas use for power generation. Moreover, US industrial gas use rate is more than ½ as large in terms of energy as the rate of use of oil products in cars and other light-duty vehicles. Assuming the same combustion efficiencies for natural gas and H_2, coal-derived H_2 with CO_2 capture/storage would emit 1/5 as much CO_2 as natural gas per unit of energy provided.

How close is current technology to enabling coal-derived H_2 to compete with natural gas in this market? Suppose that by 2025 a carbon tax is in place in the United States at a level (~ $75/t C)[34] sufficient to induce CGCC power generators to capture/store CO_2 for the co-storage option (see Figure 1). Neglecting H_2 transmission costs (e.g., assume onsite H_2 production at large industrial sites), the cost of coal-derived fuel-grade H_2 for the co-storage case would be $7.0/GJ (LHV). For comparison, the natural gas price (LHV) for US industrial users in 2025 is projected to be $4.8/GJ (EIA, 2002), which would rise to $5.9/GJ when the carbon tax is taken into account. This suggests that coal-derived H_2 based on current technology could not compete. However, comparing the cost of H_2 based on current technology to a natural gas price projected for 25 years from now under BAU conditions is not the appropriate comparison to make for an energy economy constrained by a $75/t C carbon tax. As noted earlier, the rate of demand growth for natural gas would increase even though that for total fossil energy would decrease in a climate-mitigation-constrained energy economy. Moreover, in 25 years time H_2 production costs are likely to be less than at present as a result of technological innovations—especially if H_2 can be successfully introduced as an energy carrier in the 2010-2015 time frame. Some combination of higher natural gas price and improved technology is likely to close the 15% cost gap suggested by this static calculation.

Prioritizing carbon capture/storage activities

Optimal allocation of scarce resources for carbon capture/storage requires focusing on the least costly options. Analysis of production costs for H_2 and electricity with and without CO_2 capture/storage can provide guidance in prioritizing carbon capture/storage activities. Table 5 presents a matrix of carbon taxes[35] needed to induce carbon capture/storage with the key near-term technologies discussed—with identical CO_2 storage conditions in all cases.

Notably these taxes ($/t C) are much higher for natural gas than for coal conversion systems—a finding that reflects, for the capture phase, mainly the much lower partial pressures at which CO_2 is recovered relative to coal gasification systems, and, for the CO_2 storage phase, the economies of scale in pipeline transport of CO_2 to the storage site. This finding suggests giving priority to coal systems relative to natural gas systems. Two other considerations support this judgment. First, natural gas-based energy systems typically have much lower carbon intensity than coal systems as a result of both a higher H/C ratio (4 vs 0.8) and higher energy conversion efficiency.[36] Also, if the only remaining fossil fuel resources were conventional oil plus conven-

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[34] Equivalent to a gasoline tax of $0.05/liter.

[35] These carbon taxes are the costs of CO_2 emissions avoided (see, for example, note d, Table 1).

[36] For power generation, an NGCC emits less than ½ as much CO_2 per kWh as a CGCC (see Table 1). For fuel cell cars fueled with H_2 derived from natural gas with CO_2 vented, the fuel cycle-wide GHG emission rate would be essentially the same as for a gasoline ICE car with the same fuel economy; however, because a H_2 fuel cell car is likely to be 2+ times as fuel-efficient as a gasoline ICE car, there would be a substantial climate change-mitigation benefit by shifting from the latter to a H_2 fuel cell car even with CO_2 vented. However, climate change mitigation benefits arise with coal H_2 only if the CO_2 is captured/stored (Ogden et al., 2003a).

tional and non-conventional natural gas,[37] their combustion would release 850 - 900 Gt C (see Table 6), which might be compatible with stabilizing atmospheric CO_2 at ~ 500 ppmv. These considerations collectively suggest that the carbon problem is mainly abundant coal, as well as tar sands and other unconventional oil resources that, as for coal, might best be exploited, in a climate-constrained world, to make H_2 via gasification.

There will be cases where CO_2 storage based on natural gas conversion make sense. For example, in some regions there might be good geological storage opportunities that can be exploited with natural gas but not with coal. And, with advanced conversion technologies it might be possible to narrow the avoided CO_2 cost gap between natural gas and coal systems.

The matrix presented in Table 5 also suggests that H_2 projects are preferable to electricity projects.[38] But this judgment about H_2 projects should be considered even more cautiously than the coal vs natural gas judgment, because H_2 is not yet an energy carrier. Its main relevance will be for the longer term, and then it will have to be reconsidered in light of the technologies of the time, when the avoided cost gap might be different from now.

An important consideration in prioritizing capture/storage activities is the finding that coal-derived H_2 with CO_2 capture/storage or co-storage can compete with natural gas at much lower natural gas prices than is the case for electricity (see Figure 3). This finding, as well as the favorable costs for coal H_2 relative to H_2 derived from renewable or nuclear primary energy sources, suggests that coal might have a bright future in a climate-change-mitigation-constrained world even if coal's present difficulties under such constraints in competing with natural gas in power markets cannot soon be overcome. But because H_2 won't become a significant energy carrier for at least 10-20 years, which might be well after stringent climate-change-mitigation policies are put in place (in several major industrialized countries at least), it would seem to be desirable to try to tailor such policies 'to preserve the coal option.' Technology blind climate-mitigation policies—such as imposition of a high (~ \$75-\$100/t C) carbon tax or a stringent cap-and-trade system for CO_2 emissions—could potentially decimate the coal power industry wherever natural gas is readily available, leading to substantial loss of coal energy infrastructure that would be difficult to replace later in many countries because of NIMBY constraints on siting new energy projects. However, stringent climate-change-mitigation policies that would preserve the coal option are also conceivable.[39]

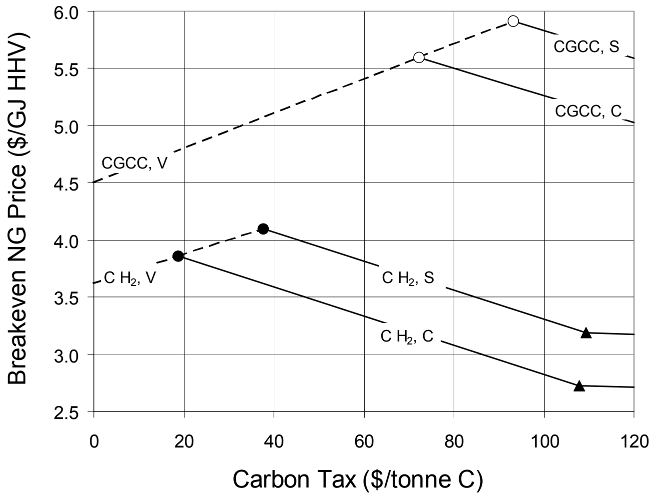

Figure 3: The least natural gas price at which the coal option with storage or co-storage is less costly than the least-costly natural gas option for making electricity or H_2

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[37] Excluding methane clathrates.

[38] The avoided cost is less for coal H_2 than for CGCC power generation largely because the water-gas-shift reactors are appropriately charged to H_2 in the former case and to carbon in the latter case.

[39] One possibility would be a cap-and-trade system (with declining emissions credits over time) that restricts trades for coal to within the coal industry. Under such a system CGCC plants with capture/storage or co-storage would be much more attractive than other options for new coal plants, and the high costs of capture/storage for such projects would be spread out over all coal consumers, leading to small average mitigation cost penalties for early projects.

The CGCC curves are the same as the least-costly options from Figure 1 for CGCC. For C H_2 the closed circles represent the same conditions as the closed circles in Figure 2. The closed triangles represent the points at which NG H_2, S or NG H_2, C becomes competitive with NG H_2, V. Source: Chiesa et al. (2003) and Kreutz et al. (2003).

Value of finding out soon if CO_2 storage in geological media is a viable option

Stabilizing atmospheric CO_2 in the range 450-550 ppmv will require deep reductions in CO_2 emissions for both electricity generation and markets that use fuels directly. Fossil fuel decarbonization/CO_2 storage is an important option for reducing emissions from the power sector, but there are alternative options that will be strong competitors in terms of cost. For markets that use fuels directly, carbon-neutral biofuels alone are likely to be inadequate to solve the entire carbon problem because of land use constraints, and it appears that H_2 is needed as an energy carrier. Costs for H_2 from fossil fuels with storage of the separated CO_2 are likely to be far less than the costs of making H_2 from water using carbon-free (renewable or nuclear) electricity or heat sources. It might one day be possible to make renewable H_2 from water using advanced photochemical processes, but such technology will at best become commercially available in the distant future and its prospective costs are unknown at present.

If CO_2 storage turns out to be a viable option for large-scale applications, the carbon problem might well be soluble at costs most people would find acceptable. But one cannot yet say with high confidence that the CO_2 storage option is viable. The value of finding out soon via appropriate projects if the fossil fuel decarbonization/CO_2 storage concept will be viable in wide applications can be gleaned from consideration of the cost implications of a *hypothetical* outcome that this concept is *not viable*, but where climate-change concerns motivate a shift to alternative carbon-free H_2 supplies. Suppose that under such circumstances coal-derived H_2 technology is not developed and that policymakers introduce a carbon tax large enough to enable H_2 generated from nuclear energy via complex thermochemical cycles or renewable electrolytic H_2 to compete with H_2 derived from natural gas with CO_2 venting. The required carbon tax would be ~ \$400/t C in the case of nuclear thermochemical H_2 and ~ \$650/t C in the case of renewable electrolytic H_2. If such carbon taxes were levied in an energy economy characterized by 1999 levels of US energy use and CO_2 emissions, retail expenditures on energy would have been ~ \$1200 billion/y and ~ \$1550 billion/y, respectively—2-3 times the actual U.S. retail expenditures on energy in 1999 (\$560 billion/y). By way of contrast, if geological storage of CO_2 proves to be a viable option for wide applications and if, in the long-term, decarbonization of electricity generation is carried out mainly by deployment of carbon-free primary energy sources and efficient natural gas conversion processes, a carbon tax of only ~ \$50/t C (or less—see Figure 2) might be fully adequate to induce CO_2 capture/storage for coal-derived H_2 and thus provide a ceiling on the price of carbon, so that solving the climate problem would increase energy expenditures only modestly (~ 13% at 1999 U.S. energy use/CO_2 emission levels if the ceiling price turns out to be \$50/t C).

A number of 'megascale' (e.g, involving geological CO_2 disposal at rates ~ 1 million tonnes CO_2 per year or more) demonstration projects along with appropriate monitoring, modeling, and scientific experiments, in alternative geological contexts, are needed. In the absence of a carbon tax (the near term situation), governments would have to pay the incremental cost (in excess of enhanced resource recovery benefits, if any) of getting the CO_2 from its sources and into the geological storage media, as well as help support the associated research. Most of the cost for such projects would be associated with paying for the CO_2 rather than the research—so low-cost CO_2 supplies are desirable. In the near term, H_2 production projects based on gasification of coal (e.g., at ammonia plants in China) or petroleum residuals[40] (e.g., at refineries[41]) to serve industrial process needs could provide CO_2 for such demonstration projects at much lower cost than either CO_2 generated as a coproduct of H_2 derived from natural gas via steam reforming or CO_2 recovered from fossil fuel power plants—if there are attractive sites for demonstrating CO_2 storage within a few tens of km of such chemical process plants and refineries. Thus, well before H_2 is introduced as an energy carrier, H_2 derived via gasification of fossil fuels can play valuable roles in exploring the space of decarbonizing fossil fuels in a climate-change-constrained world.

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[40] Gasification of petroleum residuals is a well-established commercial activity, accounting for 27 GW_{th} of syngas production capacity worldwide (44% of total syngas production capacity worldwide) (SFA Pacific, 2000).

[41] The demand for H_2 at refineries is growing rapidly (5-10%/y in the United States), driven both by the trend to heavier crudes and the need for low-sulfur fuels for transportation.

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Tables

Table 1: Performance of Alternative Fossil Fuel Power Plants[a] *(CO_2 vented vs. CO_2 captured and stored)*

Technology[b]	Emissions (*g C/kWh*), with CO_2:		Efficiency (*%, HHV basis*), with CO_2:		Generation cost (*¢/kWh*) with CO_2:			CO_2 disposal rate (t CO_2 /hour)	CO_2 storage cost (*\$/t CO_2*)	Cost of CO_2 emissions avoided[c] (*\$/t C*)
	Vented	Captured/ stored	Vented	Captured/ stored	Vented	Captured	Captured/ stored			
NGCC	92.2	10.9	53.6	43.3	4.13	6.20	6.65	117.5	9.47	310.5
Coal SCS	211	29.5	40.5	28.9	4.84	8.03	8.64	322.5	6.22	209.5
Coal UCS	200	27.6	42.7	31.0	4.79	7.83	8.39	335.1	6.08	208.8
CGCC	196	19.9	43.1	37.0	4.87	6.11	6.57	308.6	5.95	96.5

[a] Based on EPRI/DOE (2000) except that: (*i*) it is assumed the natural gas price = \$3.93/GJ—the price at which NGCC and CGCC generation costs with capture and storage are equal in the presence of with a \$96.5/t C carbon tax; (*ii*) CO_2 storage costs have been added (see footnote 3); (*iii*) costs have been converted to 2001 US dollars.

[b] NGCC unit with GE Frame 7H gas turbine [384.4 MW_e @ \$558/kW_e, CO_2 vented; 310.8 MW_e @ \$1061/kW_e, CO_2 captured]; coal SCS unit [462.1 MW_e @ \$1326/kW_e, CO_2 vented; 329.3 MW_e @ \$2295/kW_e, CO_2 captured]; coal UCS unit [506.2 MW_e @ \$1346/kW_e, CO_2 vented; 367.4 MW_e @ \$2250/ kW_e, CO_2 captured]; CGCC unit with GE Frame 7H gas turbine [424.5 MW_e @ \$1469/kW_e, CO_2 vented; 403.5 MW_e @ \$1908/kW_e, CO_2 captured].

[c] Cost of CO_2 emissions avoided (calculated relative to the same technology with CO_2 vented, as the reference case)
= (cost, CO_2 captured/stored - cost, CO_2 vented)/(emissions, CO_2 vented – emissions, CO_2 captured/stored).

Table 2: Estimated Cost of Thermochemical H_2 via S-I Process (Heat from Nuclear MHR)[a] *(\$/GJ_h)*

Capital[b]	4.35
O&M[b]	1.75
MHR heat [$C_{MHRheat}$ = cost of heat (in \$/GJ)]	$C_{MHRheat}$/0.50
Credit for byproduct O_2[c]	- 1.70
Total	4.40 + $C_{MHRheat}$/0.50
Total production cost for $C_{HTGRheat}$ = \$4.56/GJ[d]	\$13.51 (\$0.51/liter of ge)

[a] For H_2 produced @ 1,200 MW_h using the heat output from a cluster of 4 MHRs, with the MHR heat output converted at 50% efficiency (HHV basis) into H_2 via the Sulfur-Iodine (S-I) thermochemical process (Brown *et al.*, 2002; private communication from Ken Schultz, General Atomics, April 2002).

[b] Schultz projects for the Nth plant that the overnight construction cost for the S-I process is \$315/kW_t of heat input. Assuming a 4-year construction period and a 10% interest rate, the total capital required (including interest during construction) is \$365/kWt. Schultz projects that the annual O&M cost will be 7% of the overnight construction cost.

[e] It is assumed that the O_2 byproduct (8 t O_2/t H_2 or 0.056 t O_2/GJ H_2) is worth \$30.4/tonne (see note d, Table 3).

[f] Based on MHR cost estimates provided by Ken Schultz, General Atomics (private communication, April 2002) the cost of nuclear heat is estimated to be 1.64 ¢/kWh_t (\$4.56/GJ_t). If the same MHR produced instead electricity at a scale 1144 MW_e (47.7% efficiency), the installed capital cost (including interest during construction) would be \$1306/kW_e and the electricity generation cost would be 4.15 ¢/kWh_e [see Table 9 in Williams (2003)].

Table 3: Performance and Costs for Centralized H_2 Production Using Advanced Electrolytic Technologies[a]

Electrolyzer technology	Capital cost/performance targets			Plantgate cost breakdown (*$\$/GJ$, HHV basis*)					
						Electrolysis		H_2 compression	Total
	Capital cost[a] (*$\$/kW_h$*)	Pressure (*bar*)	η[b] (%)	Capital	O&M	Electricity[c]	O_2 by product credit[d]		
Alkaline or PEM (*low P, T*)	300	2	83	1.78	0.36	13.39	- 1.70	1.16	15.0 ($0.57/liter ge)
Alkaline (*high P, low T*)	400	31	80	2.38	0.48	13.89	- 1.70	0.16	15.2 ($0.58/liter ge)
Solid oxide (*low P, high T*)	900	2	111	5.35	1.07	10.01	- 1.70	1.16	15.9 ($0.60/liter ge)

[a] For H_2 produced at a scale of 500 MW_h and compressed to 60 bar. From Williams (2003) based on Ogden *et al.* (1998). The capital cost targets are much less than current capital costs: $\$600/kW_h$ and $\$1350/kW_h$ for alkaline and solid oxide electrolyzers, respectively.

[b] $\eta \equiv$ [H_2 output (HHV basis)/electricity input]. Some high-temperature heat is an input to the solid oxide electrolyzer, so that in this case $\eta > 100\%$.

[c] Assuming input of baseload electricity costing 4.0 ¢/kWh_e.

[d] By product O_2 [8 t O_2/t H_2 (0.056 t O_2/GJ H_2)] is assumed to have a value of $\$30.4$/t O_2 , the estimated cost of O_2 at an air liquefaction plant producing 3200 t/d, the maximum rate for a single-train air separation unit.

Table 4: Consumer Fuel Costs for Gasoline Internal Combustion Engine Cars and H_2 Fuel Cell Cars (excluding retail fuel taxes)

Energy carrier	Fuel cost (*¢/liter, gasoline equivalent*)		Fuel cost (*¢/km*) for gasoline internal combustion engine cars		Fuel cost (*¢/km*) for H_2 fuel cell cars (2.87 liters/100 km, ge)[c]
	Production cost	Cost to consumer	Current ICE car (*8.7 liters/100 km*)[c]	Advanced ICE car (*5.2 liters/100 km*)[c]	
Gasoline (*US average, 2000*)	25.4	30.1	2.62	1.55	-
Coal H_2 (*CO_2 vented*)	23.8[a]	61.3[a]	-	-	1.76
Coal H_2 (*CO_2 captured/stored*)	28.5[a]	66.0[a]	-	-	1.89

[a] Production costs for H_2 from coal are from Figure 1 at zero carbon tax. The estimated additional cost to the consumer includes, in addition, costs for: buffer storage at H_2 plant, transmitting H_2 via pipeline 100 km to the city gate, H_2 recompression at the city gate, distributing H_2 within the city to refuelling stations, and the refuelling stations (Ogden, 2002). The cost for the refuelling station accounts for ~ 60% of the difference between the consumer cost and the production cost [Note: $\$10$/GJ (HHV) = $\$0.38$ per liter of gasoline equivalent (ge) (LHV)].

[b] From Ogden et al. (2002). All cars have Ford Taurus size/performance. The advanced ICE car is a car that could be commercialised by 2005.

Table 5: Carbon Tax (in \$/t C) Needed to Induce CO_2 Capture/Storage in Making H_2 and Electricity[a]

Energy carrier	Feedstock for producing energy carrier	
	Natural gas with CO_2 storage	Coal with CO_2 storage
Hydrogen	~ 110	~ 40
Electricity	~ 310	~ 95

[a] Values for H_2 are from Figure 2, those for electricity are from Table 1.

Table 6: Estimated Ultimately Recoverable Conventional Oil and Gas and Unconventional Gas[a] *(HHV basis)*

	Resources (*ZJ*)	Carbon Content (*Gt C*)
Conventional Oil Resources (as of 1/1/90)[a]	11.1	211
Conventional Natural Gas Resources (as of 1/1/90)[a]	11.9	162
Subtotal	23.0	373
Unconventional Natural Gas Resources[b]	36.9	502
Total	56.2	875

[a] Identified reserves plus estimated undiscovered conventional resources are from Masters et al. (1994); estimated unconventional resources are from Rogner et al. (2000).

Monitoring to ensure safe and effective geologic sequestration of carbon dioxide

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Abstract

Reliable and cost-effective monitoring will be an important part of making geologic sequestration a safe, effective and acceptable method for greenhouse gas control. Monitoring is likely to be required as part of the permitting process for underground injection and will be used for a number of purposes, namely, tracking the location of the plume of injected carbon dioxide, ensuring that injection and abandoned wells are not leaking, and for verification of the quantity of carbon dioxide that has been injected underground. Additionally, depending on site-specific considerations, monitoring may also be required to ensure that natural resources such as groundwater and ecosystems are protected and that local populations are not exposed to unsafe concentrations of carbon dioxide. This paper reviews the methods that are available for monitoring carbon dioxide in surface and subsurface environments for on-shore geologic storage sites.

Methods for monitoring the subsurface environments include geophysical techniques such as the time-lapse 3-D seismic imaging that has been used successfully at Sleipner and the high-resolution cross-well seismic imaging that has been used to monitor carbon dioxide behavior in EOR projects. In addition, the potential for other geophysical methods such as electromagnetic imaging, gravity and tilt-meters are discussed. For monitoring geochemical interactions between carbon dioxide and the geologic formation, natural and introduced tracers, major ion geochemical indicators and pH are discussed.

Methods for monitoring carbon dioxide concentrations and fluxes on the surface range from conventional flowmeters and simple carbon dioxide sensors, to the potential for future applications of remote sensing and laser-based techniques for detecting carbon dioxide dispersed in the environment. The current state of the art and possible future for these technologies are described.

Introduction

Storing industrially generated CO_2 in deep underground formations is being seriously considered as a method for reducing greenhouse gas emissions to the atmosphere. Growing interest has lead to significant investment by governments and the private sector to develop this technology and to evaluate if this approach to greenhouse gas control could be implemented safely and effectively. Depleted oil and gas reservoirs, coal beds and deep brine-filled formation are all being considered as potential storage options. Depleted oil can gas reservoirs are particularly suitable for this purpose as they have been shown by the test of time that they can effectively store buoyant fluids, such as oil, gas and CO_2. Storage in deep brine-filled formations is in principle the same as storage in oil or gas reservoirs, but the geologic seals that would keep the CO_2 from rising rapidly to the ground surface need to characterized and demonstrated to be suitable for long-term storage. Coal beds offer the potential for a different type of storage where CO_2 becomes chemically bound to the solid coal matrix. Over hundreds to thousands of years, some fraction, including possibly all of the CO_2, is expected to dissolve in the native formation fluids. Some of the dissolved CO_2 would react and in the future become part of the solid mineral matrix. Once dissolved or reacted to form minerals, CO_2 is no longer buoyant and consequently, would no longer rise rapidly to the ground surface in the absence of a suitable geologic seal. As illustrated in Figure 1, these two fundamental ideas are the basis for secure geologic storage of CO_2 and the broad context into which the role of, and technologies for, monitoring must be assessed.

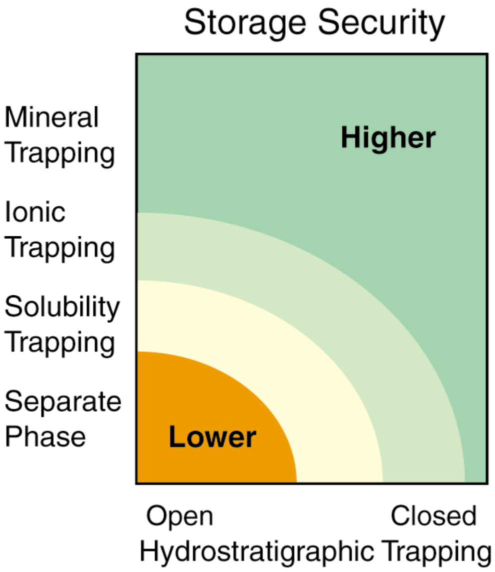

Figure 1. Physical and geochemical processes that enhance storage security

This paper focuses on monitoring technologies that are applicable to on-shore geologic storage sites. Many of the methods are also applicable to offshore storage sites. However, measurements intended to detect seepage back into the atmosphere or to detect ecological impacts would be quite different and need to be addressed separately.

The Purposes of Monitoring

Monitoring will be essential for the successful implementation of geologic storage. Regulatory oversight bodies will require demonstration that the practice of geologic storage is safe, does not create significant adverse local environmental impacts and that it is effective as a greenhouse gas control technology. Monitoring will be the primary means by which it will be demonstrated that a project meets these requirements. Figure 2 illustrates examples of requirements that are likely to be necessary for obtaining a permit to implement a geologic storage project.

While there is a broad range of safety and environmental issues that must be addressed to ensure safe and effective storage, the majority of the issues hinge on two primary factors, namely,

- the extent, location and nature of CO_2 leaks out of the primary storage structure and seepage back into the atmosphere, and
- implementation of effective controls on injection well completion, injection rates, and wellhead and formation pressures.

Therefore, from a monitoring perspective, there are two critical issues that at a minimum should be addressed. To address the first of these issues, it is necessary to be able to monitor the location of the plume of separate phase CO_2, either as a supercritical fluid or gas in the subsurface. If there were evidence that significant leakage has occurred from the primary storage structure and CO_2 has migrated to the land surface, methods for monitoring the concentration and flux of CO_2 at the land surface would be highly desirable. Meeting the second need, namely, ensuring effective injection well controls, will require monitoring the condition of the injection well, injection rates, wellhead pressures and formation pressures.

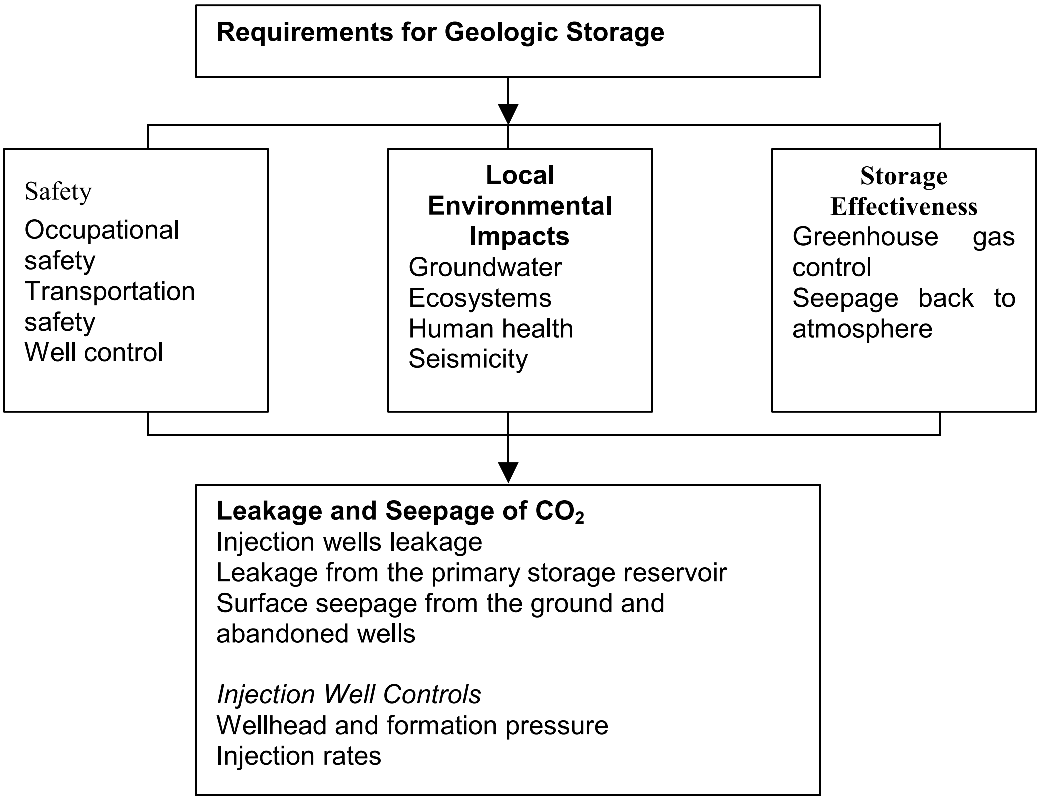

Figure 2. Example requirements for geologic storage of CO_2.

In addition to these primary factors it may also in some cases be desirable to monitor other parameters that could be helpful in assessing the performance of the storage project, or, in the event of leakage, assess the source of leakage, design a remediation scheme and assess environmental impacts, specifically:

- evaluate how effectively the storage volume is being used,
- provide information on the extent of solubility and mineral trapping,
- locate faults or other features that may be leaking CO_2 ,
- assess groundwater quality,
- detect and monitor CO_2 concentrations in the vadose zone and soils,
- monitor ecosystem impacts,
- monitor micro-seismicity associated with CO_2 injection.

While potentially of secondary importance, knowing that monitoring approaches are available to provide information about these parameters could provide greater assurance that geologic storage could be accomplished safely and effectively.

Measurement Methods

Measurement technology applicable for monitoring geologic storage of CO_2 is available from a variety of other applications, including the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, food preservation and beverage industries, fire suppression and ecosystem research (Benson et al., 2002a; 2002b). Here, we briefly review the availability and state of the art of measurement systems needed to monitor geologic storage projects.

CO_2 Flow Rates, Injection and Formation Pressures

Measurements of CO_2 injection rates are a common oil field practice and instruments are available from commercial manufacturers. Typical systems use orifice meters or other differential producing devices that relate the pressure drop across the device to the flow rate. Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control, even under varying pressure and temperature conditions (Wright and Majek, 1998).

Measurements of injection pressure at both the wellhead and in the formation are also routine. A wide variety of pressure sensors, including piezo-electric transducers, strain gauges, diaphragms and capacitance gauges are available and suitable for monitoring CO_2 injection pressures. Over the past two decades, fiber optic pressure and temperatures sensors have been developed and many manufacturers now sell these products. Fiber optic cables are lowered into the wells, connected to the sensors and provide real-time formation pressure measurements. These new systems are expected to provide even more reliable measurements and well control (Brown and Hartog, 2002).

The current state of the art is more than adequate to meet the needs for monitoring CO_2 injection rates, wellhead and formation pressures. These will provide quantitative measures of the amount of CO_2 injected at a storage site for inventories, reporting, and verification and as input to modeling.

Direct Measurement Methods for CO_2 Detection

Direct measurements of CO_2 in air, water or soils may be required as part of the monitoring program. For example, CO_2 concentrations in the air near the injection wells or abandoned wells may be monitored as a precaution to ensure worker and public safety at the storage site. In addition, nearby groundwater monitoring wells may be monitored periodically to ensure that the CO_2 storage project is not harming groundwater quality. If there is an indication that CO_2 has leaked from the primary storage reservoir and migrated to the surface, vadose zone and soil gas CO_2 concentrations may be monitored (e.g. Strutt et al., 2002).

Even in the event that the storage project poses no safety or environmental concerns, direct measurement of CO_2 concentrations and CO_2 reaction products may be wanted to assess the extent of solubility and mineral trapping. In addition, in some cases it may be desirable to have a method to uniquely identify and trace the movement of injected CO_2 from one part of the storage structure to another.

CO_2 Sensors for Measurement of CO_2 in Air

Continuous sensors for monitoring CO_2 are used in a wide variety of applications, including CO_2 demand-controlled HVAC systems, greenhouses, combustion emissions measurement, and the monitoring of environments in which carbon dioxide is a significant hazard (such as breweries). Such devices rely on IR detection principles and are referred to as infrared gas analyzers (IRGA). IRGAs are small and portable and commonly used in occupational settings. Most use nondispersive infrared (NDIR) or Fourier Transform infrared (FTIR) detectors. Both methods depend upon light attenuation by CO_2 at a specific wavelength, usually 4.26 μm. For extra assurance and validation of real-time monitoring data, NIOSH, OSHA, and the EPA use periodic gas sampling bags and gas chromatography for measuring CO_2 concentrations. Mass spectrometry is the most accurate method for measuring CO_2 concentration, but it is also the least portable. Electrochemical solid-state CO_2 detectors exist, but they are not cost effective at this time (e.g. Tamura et al. 2001).

Common field applications in environmental science include the measurement of CO_2 concentrations in soil air, flux from soils, and ecosystem-scale carbon dynamics. Diffuse soil flux measurements are made using simple IR analyzers (Oskarsson et al. 1999). The USGS measures CO_2 flux on Mammoth Mountain using LI-COR detectors, named after the company that makes them (LI-COR 2001, Sorey et al. 1996, USGS 2001, 1999). Biogeochemists studying ecosystem scale carbon cycling use CO_2 detectors on 2-5 meter-tall towers in concert with wind and temperature data to reconstruct average CO_2 flux over large areas. These eddy flux correlation measurements (ECOR) assume thorough atmospheric mixing.

Remote sensing of CO_2 releases to the atmosphere by satellites is another more complicated issue, because of the long path length through the atmosphere over which it is measured and because of the inherent variability of atmospheric CO_2. The total amount of CO_2 integrated by a satellite through the depth of the entire atmosphere is large. Infrared detectors measure average CO_2 concentration over a given path length, so a diffuse or low-level leak viewed through the atmosphere by satellite would be undetectable. In contrast, SO_2 and integrated total atmospheric CO_2 are routinely measured (Lopez-Puertas and Taylor 1989). Geologists use airborne instrumentation called COSPEC to measure the amount of SO_2 in eruption plumes, but it is not directly relevant to monitoring for surface leaks of CO_2 over large areas. A plane carries a spectrometer through the plume and measures the attenuation of solar ultraviolet light relative to an internal standard. Carbon dioxide is measured either directly in the plume by a separate IR detector, or calculated from SO_2 measurements and direct ground sampling of the SO_2/CO_2 ratio for a given volcano or event (Hobbs et al. 1991, Mori and Notsu 1997, USGS 2001). Remote-sensing techniques currently under investigation for CO_2 detection are LIDAR (light detection and range-finding) a scanning airborne laser, and DIAL (differential absorption lidar) that looks at reflections from multiple lasers at different frequencies (Hobbs et al. 1991, Menzies et al. 2001).

In summary, occupational safety monitoring of CO_2 is well established. On the other hand, while some promising technologies are under development for environmental monitoring and leak detection, carbon dioxide measurement and monitoring approaches on the temporal and space scales that are relevant to geologic sequestration could be improved with additional R&D.

Geochemical Methods and Tracers

Geochemical methods are useful both for directly monitoring the movement of CO_2 in the subsurface and for understanding the reactions taking place between CO_2 and the reservoir fluids and minerals (Gunter et al., 1998; 2001). Fluid samples can be collected either directly from the formation using a downhole sampler or from the wellhead if the well from which the sample is collected is pumped. Downhole samples are considerably more costly, but have the advantage that they are more representative of the formation fluids because they are not depressurized as they flow up the well. Methods for collecting downhole and wellhead fluids samples are well developed and geochemical sampling is conducted on a routine basis.

Fluid samples can be analyzed for major ions (e.g. Na, K, Ca, Mg, Mn, Cl, Si, HCO_3^- and SO_4) pH, alkalinity, stable isotopes (e.g. ^{13}C, ^{14}C, ^{18}O, ^{2}H), and gases, including hydrocarbon gases, CO_2 and its associated isotopes (Gunter et al., 1998; 2001). Standard analytical methods are available to monitor all of these parameters, including the possibility of continuous real-time monitoring for some of the geochemical parameters.

Natural tracers (isotopes of C, O, H and noble gases associated with the injected CO_2) and introduced tracers (noble gases, SF_6 and perfluorocarbons) also may provide insight about the underground movement of CO_2 and reactions between CO_2 and the geologic formation (Emberly et al., 2002; Blencoe et al., 2001; Cole, 2000; Kennedy and Torgersen, 2001). Tracers may also provide the opportunity to uniquely identify the source of CO_2 and in essence, answer the question 'Whose CO_2 is it?'

While it is comparatively straightforward to measure the parameters listed above, interpreting these measurements to infer information about geochemical reactions is much more challenging. In particular, little attention has been given to understanding the impact of mineral/CO_2 interactions on enhanced oil recovery. Only recently, and as a result of recent interest in geologic storage of CO_2, has a great deal of attention been paid to understanding reactions between CO_2 and deep geologic formations shortly after CO_2 is introduced into the environment (Bachu and Gunter, 1994; Czernichowski et al., 1996; Johnson et al., 2001; Knauss et al., 2001). Much remains to be learned about the kinetics of mineral/CO_2 interactions and how monitoring data can be used to predict the extent and rate of mineral and solubility trapping.

Indirect Measurement Methods for CO_2 Plume Detection

Indirect measurements for detecting CO_2 in the subsurface provide methods for tracking migration of the CO_2 plume in locations where there are no monitoring wells, or for providing higher resolution monitoring in between wells or behind the cased portion of a well. Such indirect methods fall into four categories, namely: well logs; geophysical monitoring methods such as seismic, electromagnetic, and gravity; land surface deformation using tiltmeters, plane or satellite-based geo-spatial data; and satellite-based imaging technologies such as hyperspectral and IR imaging.

The utility of these indirect methods is determined by (1) their threshold for detection of the presence of CO_2, (2) the extent to which the signal is uniquely related to the presence of CO_2 (e.g. distinguish the effects of a pressure increase from the presence of CO_2) and the (3) the degree of quantification that is possible (e.g. what is the fraction of the pore volume occupied by CO_2).

To date, 3-dimensional seismic reflection surveys have been used to monitor, with excellent success, migration of the CO_2 plume injection in the Utsira Formation in Statoil's Sleipner Vest CO_2 storage project (Korbul and Kaddour, 1995; Arts et al., 2000; 2002; Eiken et al., 2000; Torp and Gale, 2002). The success of this project bodes well for the ability of indirect methods to track plume migration in the subsurface. However, 3-D seismic reflection surveys may not always be so successful; costs for these surveys are high compared to other available monitoring methods, and in some cases, the spatial resolution or the detection threshold may not be adequate. Therefore, additional methods for plume detection are being evaluated.

Well Logs

One of the most common methods for evaluating geologic formations is the use of well logs. Logs are run by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. A wide variety of logs are available and can measure many parameters - from the condition of the well, to the composition of pore fluids, and mineralogy of the formation. For geologic storage of CO_2, like for natural gas storage and disposal of industrial wastes in deep geologic formations, logs will be most useful for detecting the condition of the well and ensuring that the well itself does not provide a leakage pathway for CO_2 migration. Several logs are routinely used for this purpose, including temperature, noise, casing integrity and radioactive tracer logs (Benson et al., 2002a). It is worth noting that the resolution of well logs may not be sufficient to detect very small rates of seepage through microcracks.

Geophysical Monitoring Methods: Seismic, Electromagnetic and Gravity

It is natural to consider geophysical techniques for monitoring of geologic sequestration because of the large body of experience in their application in the petroleum industry. Among geophysical techniques, seismic methods are by far the most highly developed. The most likely mode of application will be time-lapse, in which the difference between two surveys would be used to evaluate the movement of CO_2. As mentioned above, this technique has been used very effectively for monitoring CO_2 movement in the Utsira Formation. Though time-lapse imaging is becoming more common, it is a much less mature technology than exploration geophysics.

The applicability of geophysical techniques depends, first, on the magnitude of the change in the measured geophysical property produced by CO_2, and second, on the inherent resolution of the technique. Finally, the applicability also depends on the configuration in which the measurement is deployed.

Gravity methods sense changes in density; electrical methods primarily respond to changes in resistivity, and seismic methods depend on both density and elastic stiffness. These physical properties are known for CO_2, typical reservoir fluids, and their mixtures (Batzle and Wang, 1992; Magee and Howley, 1994, NIST, 1992) so assessments can be made of expected changes in geophysical properties. CO_2 is resistive, so electrical methods are candidates for brine bearing formations. For most of the depth interval of interest for sequestration, CO_2 is less dense and more compressible than brine or oil, so gravity and seismic methods are candidate methods for brine or oil bearing formations. At shallow depths, CO_2 has gas-like properties so none of the geophysical methods are good candidates for monitoring CO_2 within a shallow dry natural gas reservoir. Even in this case, however, since brine formations are commonly found above gas reservoirs, geophysical methods would still be candidates for detection of leaks. Research continues to refine the information available on the influence of varying CO_2 saturations on seismic and electrical properties (e.g. Hoversten and Myer, 2000; Myer, 2001; Xui et al., 2002; Hill et al., 2002).

The size of a region containing CO_2 must also be sufficient to generate an interpretable geophysical signal. A relevant concept is resolution, which, in geophysics, is defined as the ability to distinguish separate features. For seismic methods, resolution is usually discussed in the context of reflection processing, and expressed in terms of the size of the feature compared to the seismic wavelength. Seismic resolution has been addressed by Widess 1973, Hilterman, 1976, Sheriff 1997, Neidell and Poggiagliolmi 1977, Mechel and Narth 1977, and others. Vertical resolution relates to bed thickness and the critical resolution thickness is about $^1/_8$ wavelength. For thinner beds, separate reflections from the top and bottom cannot be identified. Lateral resolution is related to Fresnel zone size. When the lateral dimension is less than one Fresnel zone, reflected amplitudes are a function of size, in addition to property contrasts. Myer et al 2002, studied the resolution of surface seismic for detecting subsurface volumes containing CO_2 and concluded that, at depth, a plume as small as 10,000 to 20,000 tons of CO_2 may be detectable but would be difficult to resolve.

More recent work (e.g. Schoenberg 1980, Pyrak Nolte et al 1990) suggest that faults and fractures can be detected by seismic methods even though their thickness is much less than $^1/_8$ wavelength. Because the porosity of fractures, or a fault, is a small percentage of the total rock volume, the detectable volume of CO_2 would be much smaller than that cited above.

Seismic methods cover several frequency ranges. Surface seismic methods produce energy from 10 Hz to about 100 Hz. Crosswell seismic methods using rotary sources produce energy in the 100 Hz to 500 Hz range and using piezoelectric sources, in the 1 to 2 KHz range. Borehole seismic methods produce energy in the 10 KHz range. Frequency is related to wavelength through velocity, so for typical sedimentary rocks, wavelengths of surface seismic methods are in the range of about 10 m to 100 m, suggesting that CO_2 plumes as thin as 2 to 15 m thick may be detected. Wavelengths of high frequency borehole-deployed methods are much shorter, implying high resolution, but scattering and intrinsic attenuation limit the distance over which an interpretable signal will travel. High frequency borehole methods can penetrate only a few meters into typical sedimentary rock.

The resolution of potential field methods (essentially all geophysical methods other than seismic) is not formally defined. It is generally recognized that the resolution of these methods is much less than that of seismic.

Finally, all of the methods described above can be deployed in a number of ways, depending on the resolution and spatial coverage needed. For example, seismic data can be obtained in 2 or 3-dimensions where the seismic source and receiver are located at the ground surface. Alternatively, higher resolution data can be obtained from vertical seismic profiling where receivers are located along the length of a wellbore. Even higher resolution data can be obtained by locating the source and receivers in wellbores and imaging between them. Successful images of CO_2 migration during EOR have been obtained using cross-well seismic imaging (Wang et al., 1998). Similar configurations are applicable to electromagnetic techniques, including EM and electrical resistivity methods. Recent efforts are developing electrical resistance tomography, a simple approach that uses the wells themselves as electrodes, as a low-cost, low-resolution method for tracking CO_2 movement within a wellfield. A pilot test of this technology is underway at the Vacuum Field in New Mexico (Newmark et al., 2002).

One of the shortcomings of all these techniques is the difficulty in quantifying the amount of CO_2 that is present. For example, the presence of only a small amount of CO_2 creates large changes in the seismic velocity and compressibility of the rock (Arts et al., 2002). However, as the pore space is filled with a larger fraction of CO_2, little additional change occurs. Hoversten et al. (2002) are developing methods to quantify the saturation of CO_2 in the pore space by combining electrical and seismic imaging measurements. While it is unlikely that monitoring the saturation of CO_2 will be needed as part of a routine monitoring program, having this capability may be useful for R&D on geologic storage. Similar limitations may apply to quantifying the rate at which leakage is occurring using geophysical techniques alone. Only by combining geophysical measurements with other techniques, such as formation pressure measurements and reservoir simulation, will it be possible to obtain more quantitative estimates of leakage rates.

Land-surface Deformation, Satellite and Airplane-Based Monitoring

Recent advances in satellite imaging provide new opportunities for using land surface deformation and spectral images to indirectly map migration of CO_2. Ground surface deformation can be measured by satellite and airborn interferometric synthetic aperture radar (InSAR) systems (Zebker, 2000, Fialko and Simons, 2000). Tiltmeters placed on the ground surface can measure changes in tilt of a few nano-radians (Wright et. al., 1998). Taken separately or together these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. While these technologies are new and have not yet been applied for monitoring CO_2 storage projects, they have been used in a variety of other applications, including reservoir monitoring (Vasco et al., 2001) and groundwater investigations (Hoffman et al., 2001, Vasco et al., 2001). Satellite spectral imaging has been used to detect CO_2 induced tree kills from volcanic outgassing at Mammoth Mountain, California (Martini et al., 1999; 2000). Maturation of these technologies may provide a useful and comparatively inexpensive method for monitoring migration of CO_2 in the subsurface and for ecosystem monitoring.

The Value of Taking a Tailored Approach to Monitoring

The monitoring program for CO_2 storage projects should be tailored to the specific conditions and risks at the storage site. For example, if the storage project is in a depleted oil reservoir with a well-defined caprock and storage trap, the most likely pathway for leakage is the injection well itself or perhaps, abandoned wells from former reservoir operations (Benson et al., 2002a). In this case, the monitoring program should focus on detecting leakage from injection well, locating any abandoned wells in the area and ensuring they are not leaking CO_2 to the land surface or shallow aquifers. On the other hand, if a project is in a brine-filled formation where the caprock is less well defined or lacks a local structural trap, the monitoring program should focus on tracking migration of the plume and ensuring that is does not leak through the caprock. Similar arguments can be made about projects where solubility or mineral trapping is a critical component of the storage security. Here it would be necessary to demonstrate that the geochemical interactions were effective and progressing as predicted.

One can also imagine that the extent of land surface monitoring would depend on the size of the local population. If a project were located in an urban area, extra precautions would be put in place to assure the public that the storage project was not causing a safety or human health hazard.

The value of taking a tailored approach to monitoring is two-fold. First, the monitoring program focuses on the largest risks. Second, since monitoring may be expensive, a tailored approach will enable the most cost effective use of monitoring resources. Having said this however, it is likely that there will be a minimum set of monitoring requirements that will be based on experience and regulations from related activities such as natural gas storage, CO_2 enhanced oil recovery and disposal of industrial wastes in deep geologic formations (Benson et al, 2002a; Wilson et al., 2002).

The Importance of a Well-Defined Baseline

Carbon dioxide is ubiquitous in the environment. It is everywhere in the air, water, soils around us. CO_2 concentrations in these media can vary on daily, seasonal or longer time frames depending on the sources, sinks and long-term processes affecting CO_2 concentrations. Centuries of observation and monitoring data have also shown that the earth system is very heterogeneous, varying from place to place across the land surface and with depth. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2, but instead, it is the changes in these parameters over time can be used to detect and track migration of CO_2 and its reaction products.

For these reasons it is important to have a well-defined baseline that includes not only the average value of these parameters, but also how they vary in space and time before the project begins. This ‘time-lapse’ approach is the foundation for monitoring CO_2 storage projects and having a well-defined baseline is critical to its success. Without an adequate baseline it my not be possible to separate storage-related changes in the environment from the natural spatial and temporal variations in the monitoring parameters. For most storage projects, the monitoring baseline will be obtained during the pre-injection characterization phase of a storage project. This is particularly important for geologic storage projects in deep saline aquifers, which have less prior data than do, depleted oil and gas fields.

Using Monitoring for Model Calibration and Performance Confirmation – Comparing Model Predictions to Monitoring

One of the most important purposes of monitoring is to confirm that the project is performing as expected from predictive models. This is particularly valuable in the early stages of a project when there is the opportunity to alter the project or if it is not performing adequately, to abandon the storage site altogether. Moreover, monitoring data collected early in the project is often used to refine and calibrate the predictive model further. The refined model then forms the basis for predicting the longer-term performance of the project. This approach was successfully applied in at the Sleipner Project, where the first set of monitoring data significantly changed the conceptual model of the storage project and allowed for a much better understanding of the influence of the fine-scale reservoir heterogeneity (Chadwich, et al., 2002; Van Der Meer et al., 2002; Lindeberg et al., 2002; Zweigel at al., 2000).

Comparing model predictions with monitoring data is the key to model calibration and performance confirmation. While this is simple in principle, unless the linkage between the model results and monitoring data is considered during the design of the monitoring program, the data needed for model calibration and performance confirmation may not be available. Issues such as which parameters should be monitored, timing of measurements, spatial scale and resolution of measurements, and location of monitoring points all needed to be considered.

Monitoring Approaches

Approaches are available for monitoring many, if not all, elements of a typical geologic storage project, including:

- monitoring the CO_2 plume location,
- providing early warning that a storage site may be failing,
- monitoring CO_2 concentrations and fluxes at the ground surface,
- monitoring injection well condition, flow rates and pressures,
- monitoring solubility and mineral trapping,
- monitoring leakage up faults and fractures,
- monitoring ground water quality,
- monitoring CO_2 concentrations in the vadose zone and soil,
- monitoring ecosystem impacts,
- monitoring microseismicity.

Table 1 catalogues how the measurement techniques described previously, can be used individually or in combination, to provide a large amount of information about all of these parameters. It should however be pointed out that with today’s technology, while it is possible to detect the presence of CO_2, we have only a limited ability to make quantitative estimates of many of these parameters. Limited resolution may make it difficult to quantify the amount of leakage, should it occur. While improvements can be made and are expected in all of these areas, today’s technology provides an excellent starting point.

Table 1. Monitoring approaches for geologic storage of CO_2. Measurement methods are described in the text in the Measurement Methods Section.

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

Case Studies and Pilot Projects

Several CO_2 storage projects are now underway or are planned for the near future where the demonstration and evaluation of monitoring technology is a major focus of the project. These projects include:

- Sleipner Project in the North Sea (Korbol and Kaddour, 1995)
- Weyburn Project in Canada (Wilson et al., 2002; Moberg et al., 2000)
- Frio Formation Project in Texas (Hovorka and Knox, 2002)
- West Pearl EOR Project in SW New Mexico (Westrich et al., 2001).

In addition to these projects, several CO_2 EOR Projects have been used to demonstrate monitoring technologies for tracking CO_2 migration in the reservoir. These include the Lost Hills Oil Field in the Central Valley of California (Hoversten et al., 2002), the Vacuum Field in New Mexico (Newmark et al., 2002) and the Rangely Field in Colorado.

Natural analogue studies are beginning in Europe, Australia and the United States will also provide additional opportunities to evaluate monitoring technologies, particularly with regard detecting and quantifying surface seepage and ecosystem impacts (e.g. Martini et al., 1999; 2000).

These pioneering projects have demonstrated that many of the methods described in this paper can play a valuable role in ensuring safe and effective geologic storage of CO_2. As these methods are tested and refined their utility will increase even more.

Concluding Remarks

There are a number of issues that have yet to be addressed regarding the monitoring and verification of geologic storage projects. Among these issues are:

- Monitoring protocols and regulatory requirements for permitting and operating geologic storage sites.
- With what frequency and for how long should a storage project be monitored?
- How can a monitoring program trigger or guide an intervention program in the event that storage site begins to leak at an unacceptable rate?
- The costs of monitoring before, during and after a storage site is in operation.
- Whether or not an inventory-based approach, versus an injection-based approach should be used for verification of storage quantities and carbon credits.
- The pilot projects described above and ongoing R&D activities will help to address these issues and identify others as the technology matures.

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Monitoring of ocean storage projects

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Abstract

It has been proposed that atmospheric CO_2 accumulation could be slowed by capture of CO_2 from point sources and subsequent storage of that CO_2 in the ocean. If applied, such sequestration efforts would need to be monitored for compliance, effectiveness, and unintended consequences.

Aboveground inspection and monitoring of facilities and practices, combined with ocean observations, could assure compliance with ocean sequestration guidelines and regulations. Ocean observations could be made using a variety of sensors mounted on moorings or underwater gliders.

Long-term effectiveness and leakage to the atmosphere must be estimated from models, since on large spatial scales it will be impossible to observationally distinguish carbon stored by a project from variable concentrations of background carbon. Furthermore, the ocean naturally would absorb roughly 80% of fossil fuel CO_2 released to the atmosphere within a millennium. This means that most of the CO_2 sequestered in the ocean that leaks out to the atmosphere will be reabsorbed by the ocean. However, there is no observational way to distinguish remaining carbon from reabsorbed carbon.

The science of monitoring unintended consequences in the deep ocean interior is at a primitive state. Little is understood about ecosystems of the deep ocean interior; and even less is understood about how those ecosystems would respond to added CO_2. High priority research objectives should be (1) to improve our understanding of the natural ecosystems of the deep ocean, and (2) to improve our understanding of the response of these ecosystems to increased oceanic CO_2 concentrations and decreased ocean pH.

Introduction

Direct injection of CO_2 into the ocean interior has been proposed as an approach to slow the growth in atmospheric carbon dioxide content [Herzog *et al.*, 2001]. The direct carbon injection concept was first described by Marchetti [1977] who conceived of piping CO_2 into the outflow of the Mediterranean Sea, where it would sink deeper into the Atlantic. The idea of this approach is to bypass the slow mixing processes that would otherwise inhibit the transfer of excess atmospheric CO_2 into the ocean interior. For a specified energy demand scenario, direct injection of CO_2 in the ocean could slow CO_2 accumulation in the atmosphere, and thus global warming. However, this would be at the expense of higher atmospheric CO_2 content in the distant future, due to the energy costs of injection [Kheshgi *et al.*, 1994].

The two primary concerns about ocean sequestration are:

1. leakage of stored carbon to the atmosphere,
2. unknown consequences of elevated CO_2 concentrations, reduced ocean pH, and trace pollutants for marine organisms.

In an effort to reduce leakage and diminish pH changes, various strategies have been proposed involving limestone, fossil fuel CO_2, and seawater [Kheshgi, 1995; Rau and Caldeira, 1999, 2002; Caldeira and Rau, 2000]. Whereas the efficacy and impacts of these $CaCO_3$ based strategies may differ greatly from direct injection of liquid CO_2 into the ocean, the monitoring issues are largely identical, hence, ‘direct injection’ in this document will be interpreted to generically refer to any one of a range of strategies for introducing CO_2 into the ocean interior from point sources of CO_2 production or collection.

There are three basic purposes for monitoring the direct injection of CO_2 into the ocean: compliance, effectiveness, and unintended consequences. 'Compliance' refers to assuring that a sequestration project is actually sequestering a claimed amount of CO_2. 'Effectiveness' refers to determining or estimating the amount of CO_2 remaining in the sequestration reservoir as a function of time after initial storage in the reservoir. 'Unintended consequences' refers to possible environmental effects of a carbon sequestration project in addition to the desired goal of reducing atmospheric accumulation of carbon dioxide.

Monitoring for compliance

If a carbon sequestration strategy is to play a role in a system involving carbon credits or debits, it must be verifiable. That is, such a system of credits or debits cannot rely on trust alone; there must be some independent way of verifying carbon stored by a sequestration project.

Furthermore, the ocean may be particularly sensitive to addition of small amounts of trace metals, as evidenced by recent iron fertilization experiments (Coale et al., 1996). Therefore, there may be requirements to remove harmful chemical component from CO_2 streams intended for injected into the ocean. Small contamination of iron, manganese and aluminum, for example, may modify ocean biology dramatically. An important monitoring function will be to assure the purity of the injected CO_2 stream.

Aboveground inspection. Because direct injection into the ocean typically involves sequestration from large point sources on land, one technique for verifying compliance involves above ground inspection of sequestration facilities. Collection of samples during such inspection could verify that CO_2 is in the pipes leading to the sea, and that the CO_2 is of a composition that is consistent with other environmental regulations (e.g., trace metal concentrations, etc.). Inspected flow meters could be placed in the pipes to verify flow rates. In the case of a power plant, flue gases could be monitored for flow rate and CO_2 partial pressure, allowing a full power plant carbon audit. This carbon audit should be consistent with the amount of CO_2 claimed to have been sequestered. Depending on the separation process employed (amine, membrane, $CaCO_3$, etc.) there will be material needs for separation; an audit could help determine whether materials supplied are consistent with the claimed amount of sequestered carbon. Monetary rewards and job protection could be offered to plant employees who report evidence of fraud. This, combined with high penalties for committing fraud could help assure compliance.

Shipboard observation. In the case of shipboard dispersal of CO_2, there could be economic incentive to release CO_2 to the atmosphere or at shallow depths. Shipboard inspectors could monitor locations, depths, and purity of CO_2 release through observation of shipboard sequestration activities (laying out of pipe or tubing, etc.). Shipboard dispersal of CO_2 may be difficult to detect in the water column, but such a detection system would be an important monitoring tool. Again, rewards and protection for providers of evidence of fraud, and severe penalties for perpetrators of fraud, could help assure compliance.

Undersea monitoring for CO_2 release from fixed locations. There are a variety of strategies to monitor release of CO_2 into the water column from fixed locations. Many of these strategies can be made more effective by monitoring water velocities and flow direction near the release point.

Undersea video cameras can monitor the point of release to make sure that something is coming out of the pipes, nozzles, or release apparatus. Analysis of the video images (perhaps automated) coupled with information on water velocities can yield approximate information on the rates at which a fluid is being introduced into the ocean.

CO_2 introduced into the water column reduces ocean pH. Sensors that can measure ocean pH can be deployed around the release point. Knowledge of water flow rate and direction coupled with upstream and downstream pH measurements can be used to estimate the rate of CO_2 release.

Autonomous undersea vehicles are being developed that can be programmed to follow a variety of complex trajectories (Simonetti, 1998). For example, vehicles can be programmed to search and map out the pH field around a sequestration project. It is likely that with some research and development effort onboard CO_2 sensors could be developed that could confirm that CO_2 concentrations are elevated near the release point. Other sensors could be developed to monitor compliance with other environmental regulations (e.g., amount of trace metals and other pollutants released).

Furthermore, such vehicles could take a water sample in the high pH region for later laboratory analysis. Such analysis could verify that CO_2 is indeed the chemical producing the pH perturbation. Isotopic analysis of this CO_2 collected near the release point could confirm the fossil fuel origin of the CO_2. Additional chemical analysis could monitor for purity and compliance with environmental regulations.

Thus, it appears that there is no serious impediment to monitoring plant compliance with professed sequestration activities, although fixed location injections present fewer monitoring difficulties than do shipboard options. Such monitoring could be made significantly less expensive if monitoring could be performed intermittently and without advance warning.

Monitoring for effectiveness

There is no direct observational way to monitor how much CO_2 from a particular sequestration project is remaining in the ocean at some arbitrary time in the future.

Typical rates of advection in the ocean interior are on the order of 10^{-2} m s^{-1}. Typical rates of eddy stirring and mixing in the ocean along surfaces of neutral buoyancy (roughly horizontal) on large scales (>100 km) can be represented by eddy-diffusion coefficients of $\sim 10^3$ m^2 s^{-1} (Ledwell *et al*., 1993). Thus, after roughly 30 years ($\sim 10^9$ s), the length scale of eddy mixing is roughly 1000 km [= $\{(10^3 \text{ m}^2 \text{ s}^{-1})(\sim 10^9 \text{ s})\}^{1/2}$]. Vertical (or diapycnal) mixing is on the order of 10^{-5} m^2 s^{-1}, so a similar scaling argument suggests a vertical mixing length scale of 100 m after 30 years. These characteristic transport and mixing rates suggests that in 30 years injected CO_2 would be transported on the order of 10,000 km and mixed in a volume on the order of 10^5 km^3.

CO_2 plume monitoring may be possible for short time periods near the injection point (using carbonate chemistry, isotopes, etc.), although it is not clear how much ‘plume chasing’ is possible, necessary, or desirable. While it may be difficult to detect single project compliance observationally, the overall effectiveness should be verified through observation. Hence the international ocean storage program should seek observational evidence about the retention rate of ocean storage during the program, i.e., approximate total amount of injected CO_2 into the ocean by all the involving activities. Accurate global views of ocean DIC, alkalinity, carbon isotopes, oxygen and nutrient can be great help to now observational evidence about the effectiveness of ocean storage in the future. Thus, international research activity such as WOCE/JGOFS, and the new international decadal programs (CLIVAR, SOLAS, OCEANS) contribute helpful to future monitoring through development of an improved understanding of the distributions of chemical species prior to intentional CO_2 storage.

Given the natural background variability in ocean carbon concentrations, it would be extremely difficult, if not impossible, to detect carbon injected far from the injection source. Even if we were to assume that we could detect some elevation over natural CO_2 content, there would be no practical way to assign the elevation in CO_2 concentration to one sequestration project rather than another. In some parts of the ocean, it would be difficult to assign the elevation in CO_2 to ocean sequestration in general as opposed to CO_2 from atmospheric absorption.

CO_2 stored in the ocean leaks out to the atmosphere, but the ocean eventually reabsorbs most of this leaked carbon. It has been suggested that ocean sequestration projects should not be credited for this reabsorbed carbon [Caldeira *et al*., 2001; Herzog *et al*., in press]. If such an accounting scheme were adopted, it would be impossible operationally to separate carbon that has remained in the ocean from carbon that has leaked to the atmosphere and been reabsorbed by the ocean [Figure 1].

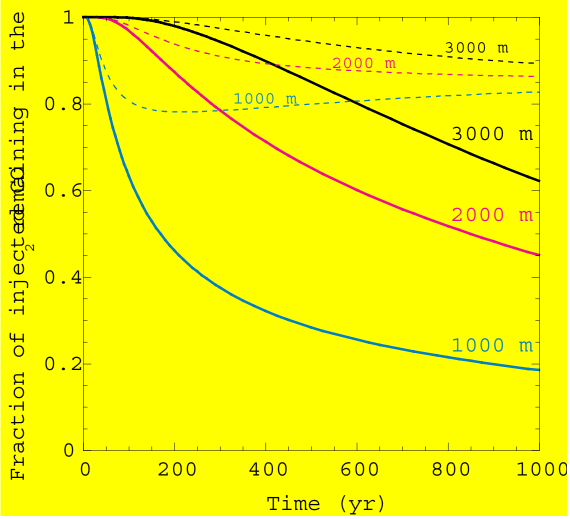

Figure 1. Fraction of injected CO_2 remaining in the ocean at three different depths as predicted by a simple ocean carbon-cycle model [Caldeira et al.*, 2001].*

Solid lines represent simulation results for injected carbon remaining in the ocean excluding CO_2 that has leaked to the atmosphere and been reabsorbed by the ocean. Dashed lines represent the amount of injected carbon remaining in the ocean including carbon that has leaked to the atmosphere and been reabsorbed. If direct observation of the ocean could detect CO_2 increases resulting from a CO_2 injection, the amounts represented by the dashed lines would be observed. However, it has been suggested that sequestration projects should be credited only with the amounts represented by the solid lines, however, there is no way to determine these amounts observationally. This could be another reason why we would need to rely on models to determine the long-term effectiveness of ocean carbon sequestration projects.

Given these considerations, the most practical path to estimating the effectiveness of an ocean sequestration project is to rely on numerical simulation. Many numerical simulations of ocean sequestration have been performed. The large-scale effectiveness of direct CO_2 injection was first simulated by Hoffert *et al.* [1979]. Since that time, there have been several simulations of deep-injection of carbon dioxide using schematic ocean models [Flannery *et al.*, 1993; Kheshgi *et al.*, 1994; Cole *et al.* 1993; Wong and Mattear, 1993] and ocean general circulation models [Wickett *et al.*, 2002; Caldeira *et al.*, 2002; Xu *et al.*, 1999; Nakashiki and Ohsumi, 1997; Dewey *et al.*, 1997; Bacastow *et al.*, 1997; Stegen *et al.*, 1993]. The Ocean Carbon-cycle Model Intercomparison Project recently completed a study of carbon sequestration in 7 ocean general circulation models [Aumont *et al.*, 2001]. These studies have generally concluded that deeper injections are more effective than shallow injections. There seems to be no simple and robust correlate of sequestration effectiveness other than depth of injection [Caldeira *et al.*, 2002], however, there is some indication that the mean retention time for stored carbon is greater in the Pacific Ocean than the Atlantic Ocean, but not all models agree on this [Figure 2]. It should be noted that for ocean sequestration approaches involving carbonate mineral dissolution some or most of the carbon released to the ocean is sequestered permanently [Caldeira and Rau, 2000].

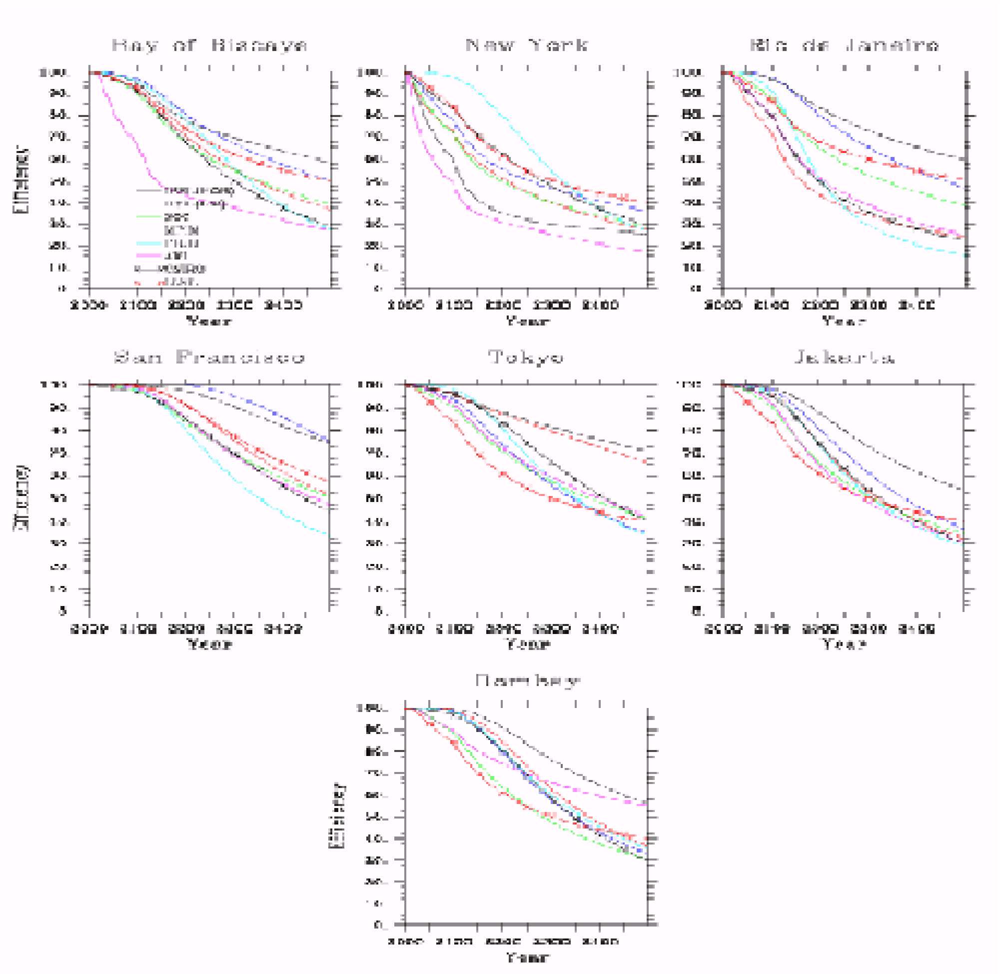

Figure 2. Comparison of sequestration results for 7 injection locations (at 1500 m depth) and 7 ocean models participating in the Ocean Carbon-cycle Model Intercomparison Project (Aumont et al.*, 2001). Models agree on overall trends but disagree on specifics.*

How is a political body to decide which model or models should be relied on if models that score similarly on quantitative metrics differ as to the effectiveness of sequestration at a given site? One way out of this quandary would be to adopt a practice-based estimate of sequestration effectiveness in lieu of detailed site-specific numerical simulation. For example, the carbon storage as a function of time after carbon release assumed for a given project could be a simple function of the depth of injection where that function is estimated based on the mean results of the models that perform best on objective quantitative metrics. While the actual carbon storage may differ somewhat from the credited carbon storage under such a system, such an approach is both simple and verifiable (in the sense that the injection depth is verifiable). As models improve, the adopted 'carbon retention function' could be improved and/or made more sophisticated.

If models are to be relied on as measures of sequestration effectiveness, and consequently, as determinants of the economic value of the sequestration projects [Caldeira *et al*., 2001; Herzog *et al*., in press], we need to build confidence in the models. Such confidence can be built through model improvement and measuring that improvement using quantitative metrics. It is thought, for example, that the ability of a model to simulate such tracers as ^{3}He, CFC-11, CFC-12, and radiocarbon will be correlated with the ability to predict retention of injected carbon.

In summary, it is not possible to observationally monitor long-term storage of carbon from individual ocean sequestration projects. Furthermore, it will not become operationally possible in the foreseeable future. Therefore, we must rely on ocean models for estimates of ocean carbon leakage and carbon remaining stored in the ocean.

Monitoring for unintended consequences

The deep ocean is a poorly understood [Karner *et al.*, 2001] and little studied portion of our planet. The deep ocean interior is generally a stable, low energy, low biomass, environment. We have little understanding of the pre-existing natural ecosystem and even less understanding of how that ecosystem would respond to increased CO_2 content. High priority research objectives should be (1) to improve our understanding of the natural ecosystems of the deep ocean and (2) to improve our understanding of the response of these ecosystems to increased oceanic CO_2 concentrations and decreased ocean pH. Such studies will be highly relevant to understanding the effects of oceanic uptake of atmospheric CO_2 on marine ecosystems.

Unintended consequences may be anticipated or could be completely unanticipated, and may occur rapidly near the injection location or distally after many years. It is easiest to monitor for anticipated possible consequences near the injection location. Researchers, notably at the Monterrey Bay Aquarium Research Institute [Seibel and Walsh, 2001; Tamburri *et al.*, 2000], have been developing experimental means for observing the consequences of elevated CO_2 on organisms in the deep ocean. These experimental approaches could be used to monitor near field consequences of direct CO_2 injection. However, such experiments and studies typically look for evidence of acute toxicity in a narrow range of species [Adams and Herzog, 1996; Caulfield *et al.* 1997; Adams *et al.*, 1997; Tamburri *et al.,* 2000; Seibel and Walsh, 2001]. We have little understanding of subtler effects on the energetic budget of organisms, how CO_2 affects reproductive fitness, and so on. Furthermore, we have extremely little understanding of how effects on individuals may propagate up to ecosystem levels. Increased CO_2 is corrosive to organisms with carbonate skeletal or shell material [Kleypas *et al.*, 2001]. It may turn out that dilute CO_2 in seawater is relatively benign except for organisms with calcium carbonate shells or skeletal material. If inadequately diluted liquid CO_2 is introduced into the ocean, one can expect corrosive effects on organisms with calcium carbonate shells and/or skeletal structures. Such anticipated possible consequences could be monitored with autonomous undersea gliders or moorings laden with appropriate sensors.

Determination of ‘acceptable’ increase in ocean CO_2 concentration is a public policy question that needs to be informed by scientific investigation. If a determination can be made, CO_2 injections can be engineered to place the CO_2 in the water as dilutely as is necessary to satisfy environmental constraints. However, such dilution will add cost to the project and hence would need to be monitored for compliance using the techniques described above.

More problematic, perhaps, is monitoring the far field for long-term consequences of large-scale widespread application of ocean carbon storage. If the carbon acidity is not neutralized with limestone or some other buffer, the addition of thousands of gigatons of carbon to the ocean will produce significant perturbations to ocean chemistry on a large scale. It is unclear at this time how best to monitor the health of broad reaches of the ocean interior, when so little is understood about these ecosystems. Again, more research is required to better understand deep-sea biota and its response to added CO_2.

Conclusions

Ocean sequestration projects should be monitored for compliance, to make sure the sequestration project is performing as claimed and is abiding by all relevant environmental regulations. Such compliance can be assured by a regime of inspection of above-ground facilities and observation of the marine environment near the injection location using autonomous vehicles or moorings equipped with pH and other sensors.

There is no observational means of monitoring ocean sequestration projects for long-term effectiveness of carbon storage. Hence, we must rely on models to estimate leakage and remaining carbon stored.

Very little is known about ecosystems of the deep ocean interior and even less is known about how these ecosystems will respond to increased CO_2. Consequently, our present ability to monitor for unintended consequences is limited. More fundamental research is needed.

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Modeling Carbon Capture and Storage Technologies in Energy and Economic Models

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Abstract

There is a growing body of literature that points to the significant potential of carbon capture and storage technologies as a means for addressing concerns relating to climate change. In particular, carbon capture and storage technologies could be fundamental to controlling the costs of addressing climate change—not only in sectors such as electric power production from fossil fuels, but it may also be key to facilitating the emergence of an affordable global hydrogen economy which is one potential promising pathway for decarbonizing the transportation sector. This paper examines the current state-of-the-art in modeling these carbon capture and storage technologies within ‘top-down’ and ‘bottom-up’ models, and explores what these types of models tell us about the potential deployment of these technologies. Generally, ‘top-down’ models represent the overall energy-economic system while ‘bottom-up’ models are more narrowly focused on the physical or geographical details of the entity being modeled. The paper identifies key knowledge gaps that need to be closed in order to improve the resolution and accuracy of these models’ projections of the deployment of carbon capture and storage technology in the near term and over the course of this century. The paper concludes by emphasizing which features of the different types of models must be combined in order to strengthen our understanding of the global potential for carbon capture and storage as a mechanism for emissions mitigation.

Introduction

Recent energy and economic modeling efforts strongly suggest that carbon capture and storage (CCS) technologies could begin deploying by 2020 and by the middle of the century could be a significant aspect of the global energy infrastructure. Deployment is projected to occur in virtually every part of the world. The deployment and utilization of CCS technologies could be massive with models projecting hundreds to even thousands of gigatons of carbon (GTC, 10^9 tonnes C, or 10^{15}gC) being stored in geologic reservoirs and oceans over the course of this century and beyond.[43] In aggregate there appears to be sufficient storage capacity in geologic and ocean reservoirs to accommodate the hundreds of GTC of storage demand projected by many models and there is theoretically sufficient capacity to store even the high end of this range in various formations.[44] Yet, carbon will be captured and stored locally. Developing a better grasp of the geographic relationship between points of capture and storage will be important in developing a more complete understanding of the potential of CCS technologies.

The large-scale utilization of CCS technologies also appears to afford society with the means to significantly reduce the cost of addressing climate change. Energy-economy model experiments have produced estimates of the cost of addressing climate change with and without carbon capture and sequestration technologies. The availability of CCS technology options has been shown to reduce costs dramatically and serves to limit the marginal cost of emissions mitigation when these technologies are able to reach their full deployment potential. These savings could amount to trillions of dollars.[45]

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[43] See for example, Hepple and Benson, 2002, which reports possible utilization of CCS technologies of 4530 GTC over the course of the millennia.

[44] Adams, et. al., 1997.

[45] Dooley, Edmonds, Wise, 1999. The availability of CCS technologies reduces total cost of stabilizing atmospheric concentrations of CO_2 by 35% or more, depending on the level of stabilization and other scenario assumptions.

Energy and Economic Models

Energy and economic models are ideal tools for understanding the interplay between energy systems, economic growth, demographic changes, climate change mandates, and technological progress.[46] The community of energy and economic modelers is actively exploring the deployment and use of CCS technologies under a wide range of conditions and scenarios. Table 1 presents an admittedly incomplete but nonetheless impressive list of energy and economic models from around the world that now incorporate CCS technologies within their modeling frameworks.[47]

To the list of models in Table 1, one could also add detailed engineering based models that would be used to help facilitate site-specific decisions about the deployment of CCS technologies at a particular plant.[48] However, this paper will not address these engineering – typically spreadsheet-based – models and will instead restrict itself to examining two general (and admittedly somewhat overlapping) categories of energy and economic models, 'top-down models' and 'bottom-up models.'

Table 1. Energy and Economic Models that Incorporate CCS Technologies

Model Name	Home Institution
AIM	National Institute for Environmental Studies
CO_2 GIS	Battelle Memorial Institute
EMCS	Carnegie Mellon University
EPPA	Massachusetts Institute of Technology
GRAPE	Science University of Tokyo
ICEM	Carnegie Mellon University
MARKAL	International Energy Agency
MESSAGE	International Institute for Applied Systems Analysis
MiniCAM	Pacific Northwest National Laboratory
NEMS	U.S. Department of Energy
New Earth 21	Research Institute of Innovative Technology for the Earth
SGM	Pacific Northwest National Laboratory

'Top-Down' Energy-Economic Models

One class of models that has been employed to examine the role of CCS technologies focuses on the interplay between the energy system and the economy. We will refer to such models as 'top-down' models. Such models are generally macro in scope, encompassing national economies and energy systems as their units of analysis. The distinguishing characteristic of these models is that they provide an internally consistent market framework to model interaction among all facets of the energy and economy through price feedback. A great variety of such top-down models have been developed.[49]

One of the principle attributes of these top-down models stems from their ability to model large scale market-based competition amongst a wide variety of energy technologies. The deployment of competing technologies is determined by the combination of technological and cost characteristics and their improvement, rates of demographic and economic development, and the stringency of modeled greenhouse gas emission abatement measures. That is, the market share for various energy technologies is not predetermined but instead varies within the model based on projected market conditions at each point in time. The various ways in which modeling groups parameterize and model the process of technological change helps to explain differences in model projections of technological adoption and costs associated with addressing climate change.[50]

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[46] Bossello, et. al. 1998 presents a good overview of this class of models.

[47] Readers are encouraged to consult a Special Issue of *Energy Economics* that has been edited by J. Weyant and R. Tol that discusses the results of the Energy Modeling Forum: Study 19. EMF Study 19 specifically addressed how models like these incorporate advanced energy technologies such as CCS. More information on the Stanford Energy Forum can be found at http://www.stanford.edu/group/EMF/home/index.htm

[48] See for example, Gupta, et. al. 2002.

[49] See for example the models cited by Weyant, and Hill, 1999.

[50] According to Edmonds, Roop and Scott 2000 differences in the way that technology is modeled is one of the most important factors in driving the results of energy and economic models. Other significant parameters that can help ex-

Other significant shared attributes of top-down models, include the ability to:

- Conduct analyses for time periods of 50 to 100 years with time steps that run from 5 to 15 year increments.
- Apply partial equilibrium or general equilibrium principles to the economic components of the models.
- Incorporate technological change explicitly, though approaches vary greatly among and between models.
- Explicitly model multiple geographic regions, allowing the exploration of when and where markets may emerge for various carbon management or energy technologies.
- Examine competition among dozens to hundreds of energy technologies and various emission abatement options under competitive market conditions for a wide variety of scenarios (e.g., carbon tax at some specified level, economically efficient climate stabilization cases, the full complement of the IPCC's Special Report on Emission Scenarios51 cases).
- Examine the sometimes synergistic benefits that arise when two or more energy / carbon management technologies are deployed in tandem (e.g., some models suggest that CCS technologies are instrumental in the development of a 'hydrogen-based economy').

Figure 1 demonstrates a few of the key attributes of this class of models through its examination of the utilization of CCS technologies (here represented as the total amount of carbon needing to be stored over the course of this century) under different assumptions of how carbon emission mandates are implemented. Note that the more economically efficient 'Tradable Permit' case requires less than 50% of the carbon storage capacity of the 'Technology Graduation' case and that the distribution of this storage requirement is more evenly spread across the globe.[52] Top-down models are particularly useful in examining energy-economic interactions such as this.

Modeling CCS Technologies within Top-Down Models

In order to model the cost and performance of CCS technologies within any top-down model, the modelers must disaggregate the cost of CCS technologies into its component costs and make assumptions about how or whether these costs vary with time. A fairly typical taxonomy for disaggregating the overall cost of CCS technologies is: (1) the parasitic energy cost of CO_2 capture,[53] (2) additional capital costs for the CO_2 capture / separations unit, and (3) the cost of CO_2 transport and storage.

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plain differences in models' projections include varying treatments of capital stock and differing assumptions on the future availability and therefore cost of various energy sources.

[51] Nakicenovic and Swart 2000.

[52] Figure 1 is taken from Dooley, Edmonds, and Wise 1999.

[53] This term would also include costs associated with additional operation and maintenance expenses associated with CO_2 removal systems such as the need to purchase amines for a CO_2 removal system.

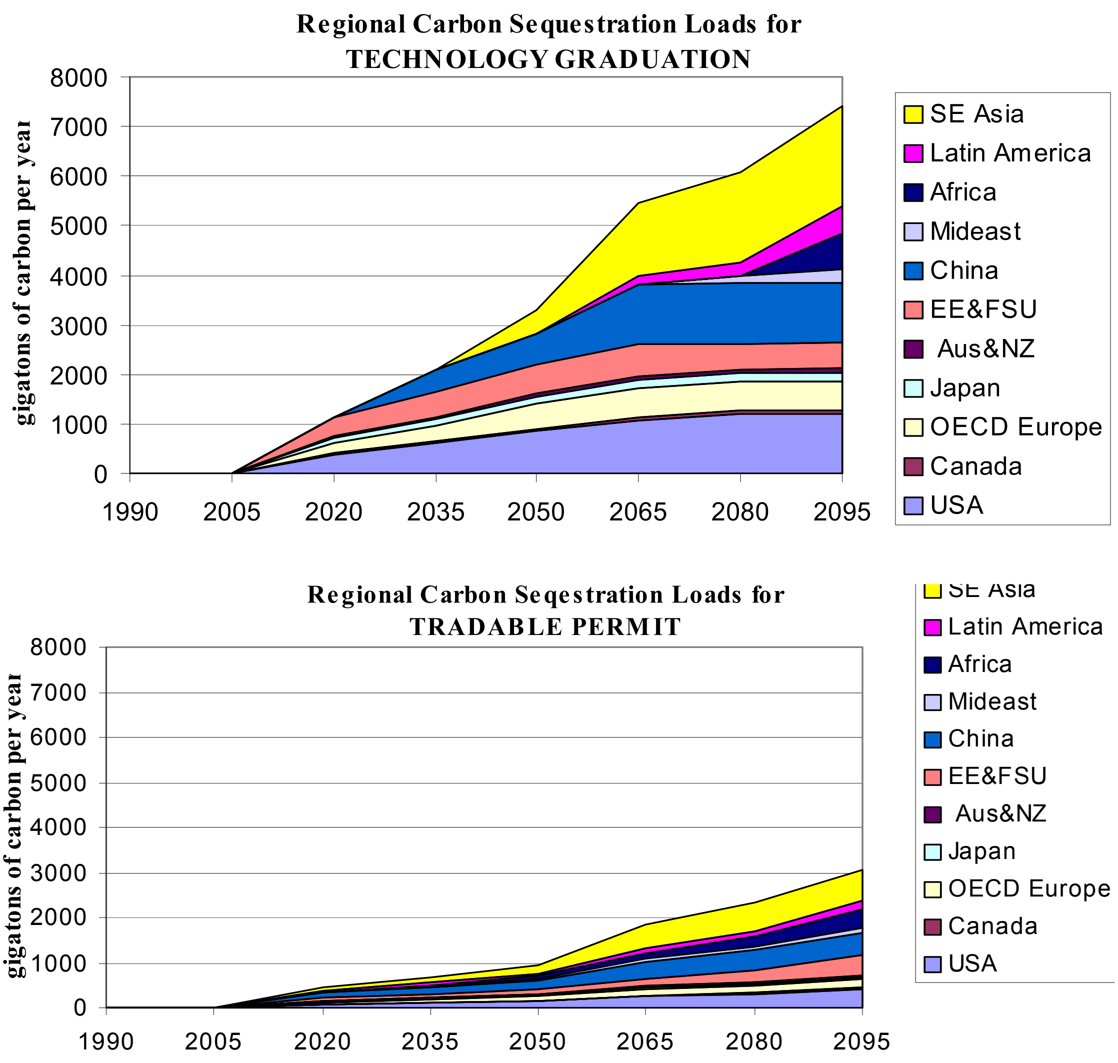

Figure 1: The Deployment of CCS Technologies Differs Under Alternative Carbon Permit Trading[54]

Cost and performance assumptions for CCS technologies in the MiniCAM 2001 are summarized in Table 2. [55] A resulting representative cost curve for CCS technologies (assuming typical gas and coal prices and conversion efficiencies) as a function of time is shown in Figure 2. It is important to note two key aspects of the data in Table 2 and Figure 2. First, the technological improvement here is exogenously specified and is driven by the modelers' estimates of potentially achievable technological improvements (i.e., these represent what is technically possible and not what is necessarily likely to occur). These assumptions can be easily updated as the research community improves its level of understanding of these technologies. Second, the resulting cost curve is heavily influenced by these assumed technological improvements.[56]

Table 2. Assumed Cost and Performance of CCS in MiniCAM 2001[57]

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[54] Note: The above Technology Graduation case demonstrates that the deployment of CCS technologies is larger and more heavily concentrated in OECD nations (thereby placing a higher demand on any geologic CO_2 reservoirs that they might have) under scenarios in which nations 'graduate into carbon constraints' depending upon their level of economic development (i.e. once a certain level of economic development is achieved the nation is required to take on emissions mitigation obligations). The Technology Graduation case requires nations that have 'graduated' to only build zero emission power plants. The 'Tradable Permit' case requires all nations to take on emissions mitigation obligations at the outset and includes an economically efficient global CO_2 permit trading regime. The Tradable Permit case results in a more even distribution of the CO_2 sequestration load across the globe and (because of the efficient allocation of carbon mitigation across all regions and all sectors of the economy) results in much less CO_2 being captured and sequestered.

[55] The most recent version of the MiniCAM is described more fully in Edmonds, et.al, 2002.

[56] Other factors would be inputs such as the future cost of coal and natural gas.

[57] Sources for the data in the Table 2: Herzog, et. al. 1997, Gottlicher and Pruschek, 1997, Freund and Ormerod, 1997.

	Coal	Oil and Gas
Energy Penalty for Carbon Capture	37% declining to 9% over 50 years from first use	24% declining to 10% over 50 years from first use
Additional Investment Costs for Capture System	54% declining to 33% over 50 years from first use	54% declining to 33% over 50 years from first use
Efficiency of Capture	90%	90%
Transport and Storage Cost	\$10/ton-C	\$10/ton-C

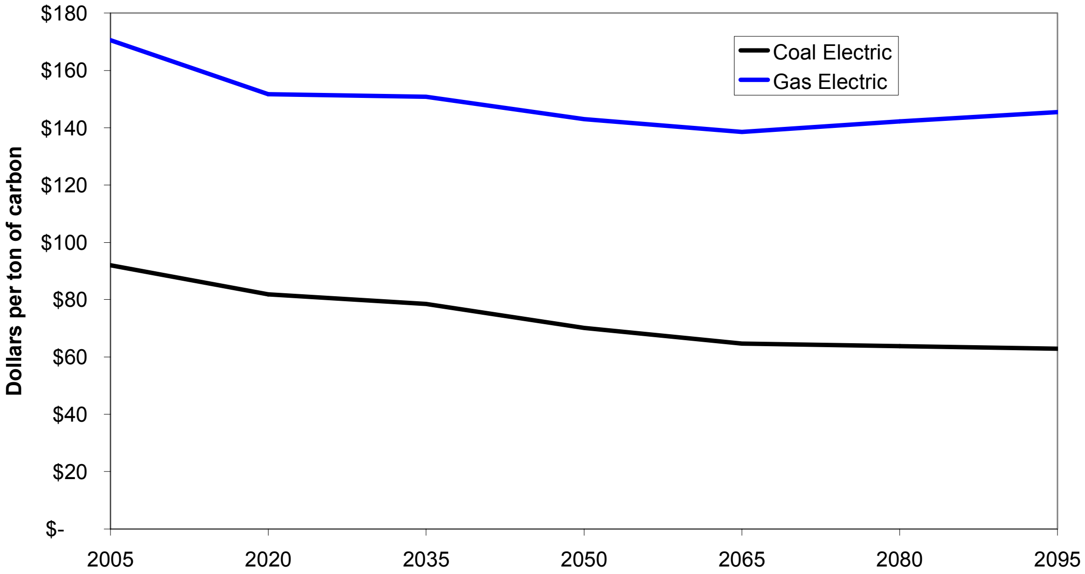

Figure 2: Representative CCS Cost Curve for the MiniCAM2001's Electric Power Sector

A point worth stressing is that the costs above are not intended to be representative of any specific carbon capture and storage system at a single point in time (e.g., these costs are not intended represent the cost of disposing of CO_2 from a new IGCC plant built in 2015 in the United Kingdom via a pipeline into the North Sea's oil fields for enhanced oil recovery). Rather, these are meant to represent a 'fleet average' for all installed CCS systems in any given region of the world. As represented here (and this is believed to be a fairly typical representation of CCS technologies in top-down models), this average CCS system's cost of operation declines with time, i.e., there is an explicit assumption that there is significant learning, which makes this technology less expensive to operate with time.[58] As specified here, the sole component of this cost reduction comes from the capture side of the system. This yields a cost curve that *over time*[59] has a negative slope.

This modeling of an average CCS system and in particular the assumption about static storage costs is driven in large measure by a lack of detailed knowledge about how this technology will perform over time and within different regions. While it is understandable to model technologies in this way as it is not clear what other assumptions would be made, the ramifications of this parameterization are worth exploring. In particular, the assumption that the cost of storage is constant with time and across all regions carries with it some very important implications. This assumption implies: CO_2 storage reservoirs are: (1) evenly distributed across the globe, (2) homogeneous, and (3) their capacity is infinite or not meaningfully constrained.

Bottom-up Models for Modeling CCS

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[58] There is ample historical evidence to suggest that the cost of energy technologies do decline with time as their market penetration increases. See for example, International Energy Agency, 2000.

[59] Since the MiniCAM 2001 runs at discrete time steps this issue of a cost curve with a negative slope needs to be caveated slightly. *In any given time step* (e.g., the year 2030), the model behaves as if all emission abatement options are grouped together and that this group has an abatement cost curve with a positive slope. In layman's terms, in any given time step, the model seeks to use the cheapest emissions mitigation options first and then progresses to more expensive options until the emissions mitigation target is achieved. However, *over time* the cost curve for CCS technologies is negative.

As discussed above, one of the key limitations of the current modeling of CCS technologies within top-down models is that, at present, they model the technology – and in particular the CO_2 storage/ reservoir aspects of CCS systems -- as if it were a homogenous resource available at any point in space and time for a given price. However, it is clear that CO_2 storage reservoirs are not homogeneous across the globe. The literature points to -- if nothing else -- differing net costs for CO_2 storage related to enhanced oil recovery (EOR) as opposed to storage in a deep saline formation.[60] The literature also demonstrates that these reservoirs are not uniformly distributed around the globe and that there is reason to believe that some regions will have more of these reservoirs than other regions, which suggest that the cost of utilizing CO_2 storage as a function of time should vary between regions.[61] Lastly, these reservoirs are known to have finite (although sometimes quite large) capacities.[62] There is even an emerging set of studies that specifically attempts to identify 'early opportunities' for CCS deployment, i.e., there is an explicit recognition that society would seek to exploit lower cost CCS opportunities before moving towards more expensive CCS options in the future.[63] It is therefore clear that the assumption that CO_2 storage reservoirs are homogeneous and therefore the cost of CO_2 storage is constant with time and across the globe is inadequate.

A wide range of engineering studies have been undertaken examining the cost of CCS technologies.[64] These studies form the first generation of 'bottom-up' CCS models. A second generation of bottom-up CCS models is beginning to emerge. These models build on the foundations of the engineering studies, but provide more detailed descriptions of technology and geography. Some bottom-up models now describe the location and character of existing large CO_2 point sources (e.g., power plants) and potential CO_2 reservoirs in the context of CCS options.

By their very definition, bottom-up models are more focused on a particular aspect of the energy system, making generalizations across the universe of bottom-up models less meaningful. Current bottom-up CCS models are moving toward a focus on incorporating geographical and physical details of CO_2 capture, transport, and storage. In contrast, prominent bottom-up energy system models, like the MARKAL and MESSAGE models listed above, have yet to focus on the geography of CO_2 storage. As a consequence, they currently do not have any more detail on CO_2 storage resources and costs than do the top-down models discussed above. However, the additional energy system detail that exists in these bottom-up energy models, such as powerplant dispatch, would certainly provide additional analytical richness to the modeling of CCS technologies.[65]

Modeling CCS Technology and Geography

The most recent additions to the 'bottom-up' CCS modeling genre explicitly incorporate both technology and geography through the use of geographic information system-based (GIS) frameworks.[66] These new GIS-based models are conceivably a significant step forward in our ability to model CCS technologies as they now contain all major components of the cost of CCS technologies (i.e., the parasitic energy cost of capture, the additional capital for the capture system, the cost of transport, and the cost of storage) explicitly being modeled and variable depending upon the specific characteristics of individual source / sink pairs.

The ability to model the characteristics of specific source / sink combinations allows for the construction of a bottom-up cost curve and projected deployment schedule. Figure 3 illustrates a *very rough* cost curve for the 185 existing coal- and natural gas-fired power generation units in the United States located in Illinois, Indiana, Ohio and West Virginia assuming that they can not transport their CO_2 more than 100 miles from the power generating unit. While data displayed in Figure 3 is purely illustrative, the shape of the resulting cost curve is worthy of note.

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[60] See for example, Adams, et. al. 1997.
[61] Dahowski and Dooley, 2002.
[62] Gupta et. al., 2001.
[63] Damen, et. al., 2002.
[64] See for example, Herzog, et. al. 1997, Gottlicher and Pruschek, 1997, and Adams, et. al. 1997.
[65] Johnson and Keith 2001 provide an interesting and preliminary indication of the usefulness of being able to incorporate dispatch when attempting to model the utilization of CCS technologies.
[66] See for example, the model described in Dahowski, et. al., 2001.

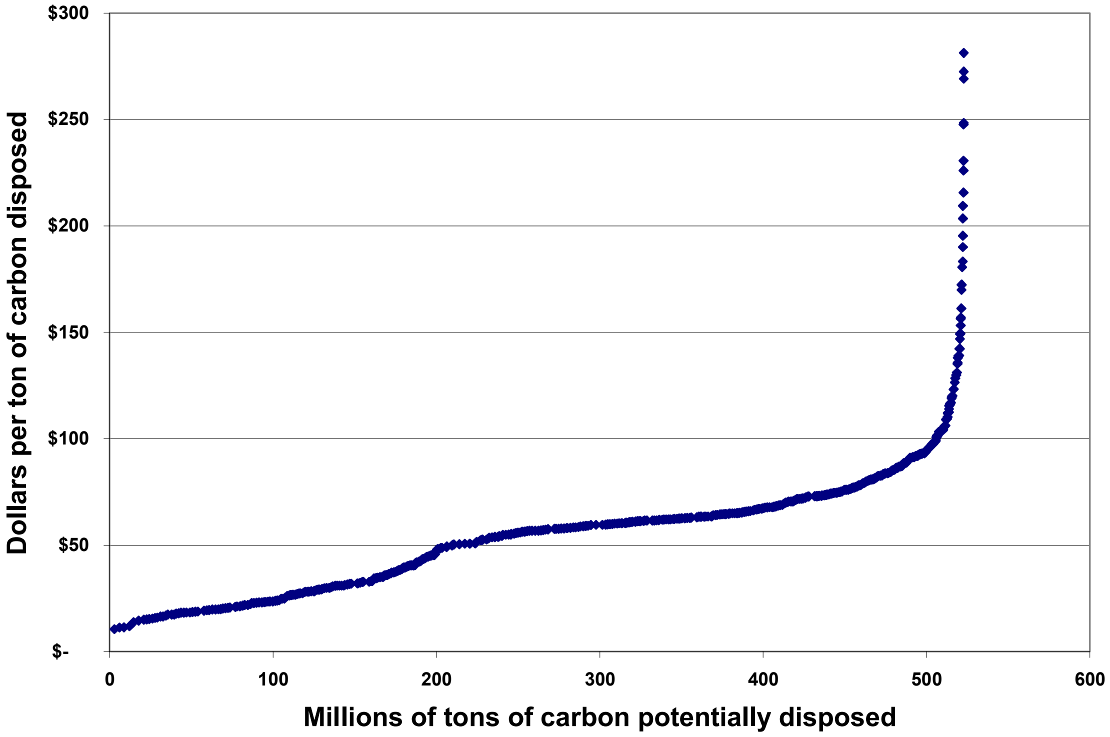

Figure 3. Rough Cost Curve for Existing Power Plants in Illinois, Indiana, Ohio and West Virginia (Search Radius 100 miles)

The cost curve is *upward sloping,* that is, the greater the demand for carbon storage, the higher the marginal cost. It is also -- in this particular region of the US -- everywhere positive. The marginal cost of CCS rises almost linearly with deployment through most of this range, but then increases sharply. Figure 3 clearly indicates the existence of power plants for which products derived in the storage process (e.g. methane or oil recovered from so called value added formations) are sufficiently valuable that they could substantially offset the costs of capture and storage. Other power plants appear to be less favorably located (are farther away from a value-added formation requiring longer pipelines or are located only near deep saline formations that are unlikely to yield any form of offsetting credit) and therefore have higher costs. If the search radius were increased, say to 500 miles, this cost curve would be somewhat flatter but would still slope upwards. That is, the cost curve would still reflect the reality that there is a finite capacity of relatively inexpensive storage options, and, once that capacity was consumed, we would have to move to the next most expensive grade of reservoir. If the demand for CO_2 storage were great enough, we would eventually reach a point where the cost curve sloped steeply upwards. Other recent bottom-up analysis of CO_2 driven enhanced oil recovery and enhanced coal bed methane recovery also report upward sloping cost curves.[67]

It is worth noting, that in contrast to Figure 1, which mapped the marginal cost of capture and storage against time, Figure 3 shows the relationship between cost and storage at a particular moment in time. A key difference between this cost curve for CCS technologies applied to these existing plants and the cost curve for CCS technologies embedded in a top-down model is that the cost curve in Figure 3 was endogenously generated within the model by carrying out a series of pair wise least cost calculations for every source sink combination. In contrast 'top-down' cost curve that is exogenously specified and is derivative of analyses of potential aggregate CCS technological regimes.

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[67] See for example, International Energy Agency Greenhouse Gas R&D Program 1998 and International Energy Agency Greenhouse Gas R&D Program 2002.

Knowledge Gaps

The study of CCS technologies in an economic context is relatively new. While early efforts to consider CCS date to the late 1970s,[68] the systematic incorporation of CCS technologies into energy-economic models of national and global emissions of greenhouse gases does not begin until the latter part of the 1990s.[69]

In general, the literature that has emerged has shown that CCS technologies hold the potential to become a major component of the global energy system during the 21st century and are capable of helping to deliver significant, sustained and cost effective emissions reductions. Nevertheless, many questions remain to be addressed. The finer grained details of how and when this class of technologies will deploy remain elusive. For example, disagreement remains across models as to cost and performance, and the conditions under which deployment begins within any region.[70] Much of this uncertainty can be traced to uncertainties in the nature of the technology and the institutional environment in which CCS technologies will be deployed. There is no substitute for an experiential record. Some of the required knowledge awaits the execution of well-designed and meaningfully scaled field demonstrations of integrated capture and storage systems. Specific issues to be addressed include:

- *CO_2 capture cost estimates from non-power industrial facilities:* Recent estimates state that globally there are more than 14,600 large CO_2 point sources. More than 45% of these point sources are from various industrial plants and not from electricity producing power plants.[71] Emissions from sources such as cement kilns, steel mills, chemical refineries, gas processing facilities, etc., could also be addressed via the deployment of CCS technologies. These non-electric power CO_2 point sources potentially represent early opportunities for capturing CO_2 at relatively low cost as many of them produce relatively pure CO_2 gas streams. It would be very useful to obtain a better understanding of how many of these more than 14,600 large CO_2 point sources lie in close proximity to various geologic CO_2 storage reservoirs.
- *CO_2 injection costs:* Top-down and bottom-up models typically assume a fixed cost for the CO_2 injection cost component of the overall cost of storage. Yet there is a growing body of literature derived from process-based models of fluid flow and dispersion in CO_2 reservoirs that suggests that these costs will depend on site-specific characteristics and should therefore be variable.[72] We also now have field data to substantiate this. For example in the Sleipner project, there is one injection well that injects 1 million tons of CO_2 per year into the Utsira formation.[73] Yet in a recent report that estimated the cost of CO_2 driven enhanced coal bed methane recovery an assumption was made that 41 (injection and production) wells would be needed to handle a mere 120,000 tons of CO_2 per year.[74] When one considers that a typical large power plant would generate millions of tons of CO_2 per year, it is important to develop a better understanding of the number of injection wells needed to handle a power plant's CO_2. Given that most economic models would need aggregate and not site-specific information on these costs, it is important to ask if it is possible and meaningful to attempt to estimate rules of thumb like X number of wells per Y million tons of CO_2 for an 'average deep saline formation' or an 'average coal seam.'
- *Pipelines and infrastructure costs:* It will also be important to learn how to model the emergence of regional CO_2 pipeline networks as it appears that these pipeline networks will emerge if the deployment of CCS technologies approaches levels suggested by top-down models. Currently, most analyses (and in particular on-shore CO_2 transport schemes, as opposed to ocean-based storage schemes) that consider distance as a variable for costing CCS deployment assume a one-to-one matching of source and sink. Yet, the Permian Basin in Texas is a real world demonstration of the fact that if there is a large enough demand for

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[68] See for example, Marchetti, 1977, Steinberg, 1983; and Steinberg et al. 1984.

[69] See for example, Edmonds and Wise, 1998.

[70] To cite just one of many possible examples, two relatively recent studies report costs for capturing CO_2 from a 500MWe coal plant using an amine based CO_2 capture system that are remarkably close to each other at $47 per ton of CO_2 avoided. Yet while these two studies report similar cost of CO_2 capture from this nominal 500MWe conventional coal plant, when the authors begin to explore various capture technology system configurations their estimates of the increase in the cost of electricity from this plant vary considerably spanning an increase of 1.7 times to an increase of more than 6.6 times the cost of electricity without CO_2 controls for the same plant. See Aldus, 2001 and Rao and Rubin, 2002.

[71] Hendricks, et. al., 2001.

[72] See, for example, Law and Bachu 1996.

[73] Source. Statoil website. http://www.statoil.com/STATOILCOM/SVG00990.NSF/web/sleipneren?opendocument

[74] International Energy Agency Greenhouse Gas R&D Program, 2000.

CO_2 in an area a pipeline infrastructure will likely develop.[75] A one -to-one matching of source-sink appears inadequate and likely inflates models' cost for using CCS technologies, but it is not obvious how one would model the emergence of CO_2 pipeline networks as a function of time.

- *Carbon retention rates:* A number of recent papers have speculated on retention rates for various classes of CO_2 reservoirs (including the ocean). Improved estimates of retention rates are needed to help better understand the long-term market potential for CCS technologies.[76] Better estimates of retention rates should emerge through field experiments in various classes of reservoirs.
- *Extent of 'value-added' opportunities:* There is a growing literature which suggests that some applications of CCS technologies might have negative or relatively low costs when CO_2 can be used to produce valuable hydrocarbons–either oil or natural gas–whose proceeds could be used to offset the cost of CO_2 capture and transport. It is therefore important to compile a much better understanding of the scale and geographic distribution of these so-called value added reservoirs.[77] It will also be important to understand the system dynamics of the variable[78] CO_2 injection rates used in these value added reservoirs and whether these dynamics influence the economics of using CO_2 in value added formations.
- *Capacity and location of all potential reservoirs:* It is important to identify by location and potential capacity all possible CO_2 storage reservoirs wherever in the world they may exist. Stabilization of the concentration of CO_2 cannot be accomplished without participation of all major carbon-emitting countries. Thus, future markets for CCS adoption will lie outside of the current OECD.[79] Therefore we need to map CO_2 storage reservoirs around the world and not just in the US, Western Europe, Japan, Canada, and Australia, which are often seen as the likely first markets to adopt CCS technologies.

Future Modeling: Integration of Top-Down and Bottom-Up Approaches

The energy modeling community has long wrestled with how to bring the real world insights of the bottom-up models into the top-down framework of global, energy and economic models. There are many reasons that this integration has not occurred to date. Chief among them is the disparity in the spatial and temporal scales of the two approaches. Bottom-up models often have greater spatial and temporal disaggregation compared with the more highly aggregated and broader scoped top-down models. For example, while some bottom-up models might specifically examine current CCS deployment opportunities by examining the location of sources and sinks among existing power plants, it is not at all clear how this very detailed and site-specific information would be moved into a longer term analysis that might be run using a top-down model (e.g., what are likely power generation sites in the year 2050). Furthermore, the size of future power generation facilities may well play an important role in shaping the economics of CCS deployment.

However, there are advantages to developing models with characteristics of both approaches.[80] The integration of these two approaches would give analysts a better tool to describe realistic deployment scenarios for CCS technologies and to understand how these technologies compete with and complement other mitigation options. In particular, the ability to better integrate these two modeling frameworks (or at least integrate insights generated through these frameworks) would facilitate a better understanding of the interactions of technological innovation and site-specific issues in the deployment of CCS technologies over time. Resolving the interplay between technological improvement (a force for reducing costs) and obtaining a better under-

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[75] Sass et. al., 2001 includes a table that clearly demonstrates that a network of main trunk lines of up to 30 inches in diameter and 500 miles in length feed CO_2 into the EOR projects in the Permian Basin and that branching off of these trunk lines are smaller lateral pipelines as small as 8 inches in diameter and tens of miles in length that feed specific fields. Hart's Petroleum Engineer International, 1995 displays a map of the Permian Basin CO_2 pipeline network.

[76] See for example, Hepple and Benson, 2002, Dooley, et. al, 2002, or Pacala, 2002.

[77] See for example, International Energy Agency Greenhouse Gas R&D Program, 2000 and 2002.

[78] CO_2 driven EOR fields typically employ what is called a WAG (water alternating with gas) production method. The periodicity that separates gas (i.e., CO_2 injection) phases varies from field to field and even from well to well and can also vary as a function of time. Petroleum Engineer International, 1995.

[79] Dooley, et. al., 1999 contains modeling projections demonstrating how CCS technologies might deploy globally.

[80] McFarland et.al., 2002 present a good example of one route to bring bottom-up insights about CCS technologies into a top-down model.

standing of site specific and reservoir specific considerations (likely a force for increasing costs with time) is a central modeling question concerning CCS technologies.

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Annex A Workshop Programme

Day	**Time**	**Title lecture**	**Speaker**
Nov-18	10:00	Discussion on carbon storage in Canada and the development of a protocol going on at the time	Malcolm Wilson
	12:30	*Lunch*	
	13:30	Site visit to Encana CO_2 storage oil field in south Saskatchewan	Malcolm Wilson
Nov-19	9:00	Introduction notes	Bert Metz/Ogunlade Davidson (co-chairs IPCC Working Group III)
	10:30	*Coffee break*	
	11:00	a) Overview of sources, potential, transport and geographical distribution of storage possibilities	John Gale (IEA GHG R&D programme)
	11:45	b) CO_2 capture and re-use	Kelly Thambimuthu (Energy Technology Centre, National Resources Canada, CANMET, Chairman IEA GHG R&D programme)
	12:30	*Lunch*	
	13:30	c) Geological storage, including costs and risks, in saline aquifers	Olav Kårstad (Statoil)
	14:10	d) Geological storage, including costs and risks, in oil, gas and unminable coal seams	Ton Wildenborg (Netherlands Institute of Applied Geoscience TNO)
	14:50	e) Ocean storage, including costs and risks	Takashi Ohsumi (Research institute for Innovative Technology for the Earth)
	15:30	*Coffee break*	
	16:00	f) General overview of costs	Paul Freund (IEA GHG R&D programme)
	16:40	g) Environmental impacts and risks	Paul Johnston (Exeter University/Science director Greenpeace)
	17:20	h) Legal and political aspects; impediments and barriers	Jip Lenstra (Climate Division of Dutch Ministry of Environment)
	18:00	End of first day	

Day	Time	Title lecture	Speaker
20-Nov	9:00	i) Review of outstanding issues with regard to greenhouse gas inventories	Taka Hiraishi (IPCC Task force National Greenhouse gas Inventories Programme)
	9:30	j) Implications of long-term technological and economical possibilities (zero-carbon energy carriers)	Bob Williams (Princeton)
	10:10	*Coffee break*	
	10:50	k) Monitoring of storage projects - geological storage	Sally Benson (Lawrence Berkeley National Laboratory)
	11:30	l) Monitoring of storage projects - ocean storage	Ken Caldeira (Lawrence Livermore National Laboratory)
	12:10	m) Carbon storage in energy and climate models	Jim Dooley (Pacific Northwest National Laboratory)
	13:00	*Lunch*	
	14:00	Parallel working groups on each predetermined topic (ca. 8 parallel sessions)	
	18:00	End of second day	
21-Nov	8:00	Continuation working groups	
	11:00	*Coffee break*	
	12:00	Workshop wrap-up	Bert Metz/Ogunlade Davidson (co-chairs IPCC Working Group III)
	13:00	*Lunch*	
	14:00	Start of meetings on scoping paper	Closed drafting group
	18:00	End of third day	
22-Nov	9:00	Continuation meeting on scoping paper	Closed core group
	12:30	Finalisation draft scoping paper	

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