BUILDING THE COST CURVES FOR CO_2 STORAGE: EUROPEAN SECTOR

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Background to the Study

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

IEA GHG has now embarked on a programme of work to derive the regional costs for CO_2 storage. To begin the process of developing the costs for geological storage of CO_2 an initial baseline study was completed. The baseline study reviewed the major sources of anthropogenic CO_2, and developed a global database of CO_2 emission sources detailing quantities and locations. This data base contains details of over 14 000 large emission point sources from the power and industry sectors[1]. Following on from the baseline study two regional studies have now commenced, one in Europe and one in North America[2]. A third study in the series for India was agreed at the 26th ExCo meeting (Vancouver, Canada). The regional information developed in these studies, along with data on the costs of capture and transmission[3], can then be combined to allow future assessments of the comparative costs between CO_2 capture and storage and other mitigation options, such as renewable fuels to be undertaken[4].

This report reviews the development of a CO_2 storage cost curve for Europe. The study has been carried out by The Netherlands Geological Survey (TNO-NITG) in co-operation with the geological surveys of Britain (BGS) and Denmark and Greenland (GEUS) and ECOFYS.

Results and Discussion

The following aspects are discussed in this report:

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

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[1] IEA Greenhouse Gas R&D Programme report no. PH4/9, Building the cost curves for CO_2 storage, Part 3: Sources of CO_2, July 2002.
[2] IEA Greenhouse Gas R&D Programme report no. 2005/3, Building the cost curves for CO_2 storage, Part 3: North America, March 2005.
[3] The costs of capture and transmission of CO_2 will be compiled in separate studies and then combined with the storage costs at a later date.
[4] A comparative assessment study between CO_2 capture and storage and some renewable options was agreed by members at the 24th ExCo meeting, Paris France.

Study scope and methodology

The study has assessed geological storage opportunities in Western Europe covering both on-shore storage and off-shore storage, principally in the North Sea. The study extended an earlier European Commission research project (GESTCO[5]) which studied the geological capacity in North West Europe (Norway, Denmark, Britain, Germany, the Netherlands and France) and Greece. This study included data on the following countries: Austria, Switzerland, Sweden, Finland, Spain, Italy and Iceland in the European analysis.

The CO_2 storage options considered in the study included:

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

The cost curves for each storage option were developed by compiling data on geological reservoirs for CO_2 storage and determining the technical storage capacity of these reservoirs. This data, along with the baseline study data on CO_2 sources, were then input into a Geographic Information System (GIS). The GIS also allowed the distances between the sources and the storage reservoirs to be determined so that the cost for transmission of CO_2 could be derived[6].

Point source emissions

IEA GHG provided the GESTCO project with a copy of its European data set on large point source emissions. That dataset was then updated for the 8 GESTCO study countries by the project in 2003 and then incorporated into IEA GHG's European data set for use in this study. The database on large point source emissions for the European area contains 1 917 different point sources of CO_2, of which 1 352 plants have annual emission of 100 000 tonnes or more. The remaining 565 large point sources emit less than 100 000 tonnes/y and contribute for only 1% to the total emissions; hence these plants were not considered in the later cost curve analysis. The total estimated annual emissions in the database sums to 1.5 $GtCO_2$. Plotting the annual emission versus the number of plants (Figure 1) indicates that 400 plants represent 75% of all emissions. A similar situation was observed in the North American study with 500 plants dominating the regions emissions. Further fifty percent of all emissions originate from less than 10% of all plants. The share of the power production sector in the database amounts to about two-third of the total emission.

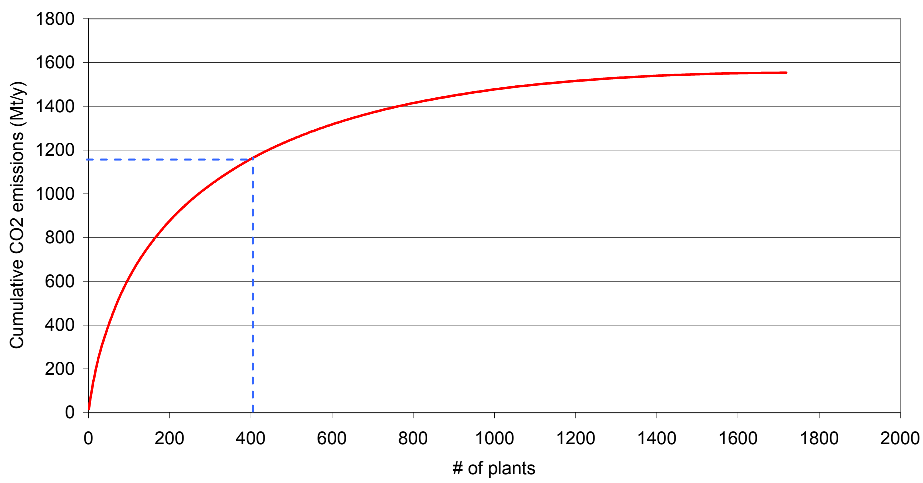

Figure 1. Cumulative Emissions of CO_2 from Large Point Sources in Europe.

[5] GESTCO is the abbreviated project title, the full title is: European Potential for Geological Storage of CO_2 from Fossil Fuel Combustion.
[6] IEA GHG's transmission calculator was used to derive the CO_2 pipeline costs in this study.

The distribution of the large emission point sources in Europe is illustrated in Figure 2. The figure shows that high concentrations of CO_2 emissions can be found in the Ruhr area in Germany, in the Rijnmond area in the Netherlands and in Central/Eastern part of the United Kingdom.

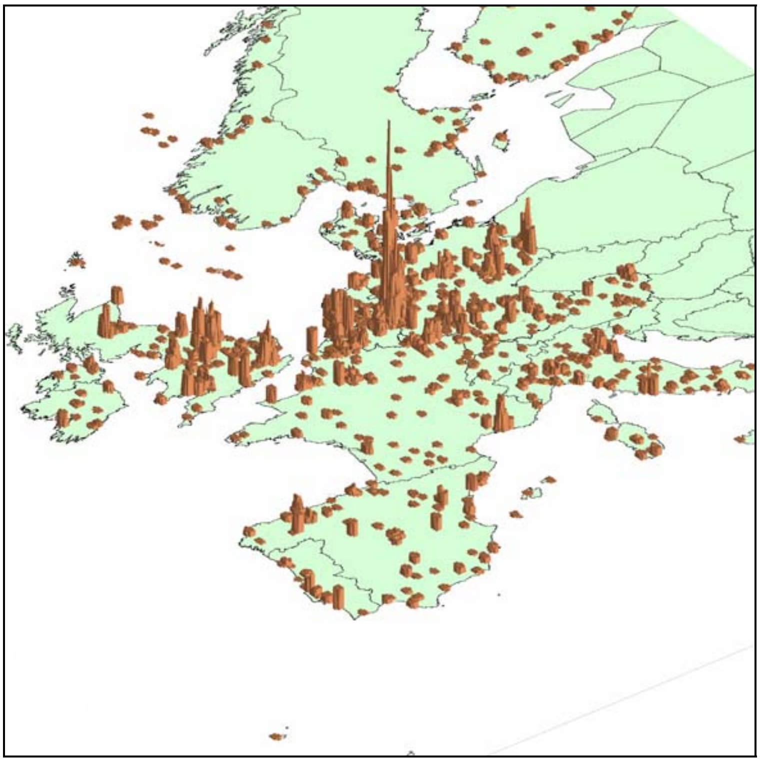

Figure 2. Graphical Representation of Size of Annual CO_2 Emissions from Large Point Sources in Europe

Geological storage capacity in candidate reservoirs in Europe

The geological storage capacity for Europe has been estimated at up to 1550 Gt CO_2. Of which up to a 1 500 Gt of CO_2 can be stored in deep saline formations most of which are situated in the North Sea. The total capacity of hydrocarbon fields in Europe is estimated at more than 40 Gt CO_2, 7 Gt of which can be stored in oil reservoirs. Whilst the storage capacity of European deep unmineable coal seams at a depth of 800 to 1500 m is estimated at about 6 Gt CO_2. The methodology used to calculate the storage capacity is presented in detail in the main report. It is noted that the best dataset available was for oil and gas fields in Europe, whilst the lowest quality available datasets were for deep saline aquifers and deep unmineable coal seams.

Costs of CO_2 Storage

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

Table 1. Summary of Storage Costs for Different Geological Formations

Storage formation	Typical Storage Cost (2000) €/t CO_2	Storage Cost Range (2000) €/t CO_2
Confined aquifers	1 to 2.5	0.6 to 6
Depleted gas fields	2	0.75 to 5
Depleted oil fields	1 to 3	1.5 to 7.5
CO_2-EOR	30	6 to 80
CO_2-ECBM	40	-

Costs for storage alone in geological formations such as deep saline formations and oil and gas reservoirs are typically €1-3/t CO_2. Costs for storage in CO_2-EOR and CO_2-ECBM schemes, however, are an order of magnitude higher. The high cost for CO_2-EOR reflects the need for either a platform refurbishment or new platform to allow injection of CO_2 combined with oil production. For CO_2-ECBM the high cost reflects that there are no good quality coal basins in Western Europe that are suitable for CO_2 injection and methane recovery.

It is noted that the net storage costs in Europe are significantly lower than those derived for the North American study, where typical storage costs were \$12/t CO_2[7] in deep saline aquifers and gas fields. The difference in the net storage costs is considered to be primarily due to the different well injectivity rates used in the two studies. In the North American study well injection rates were taken from actual operational experience in CO_2-EOR projects and liquid injection into aquifers. Injection rates for deep saline aquifers and gas fields in the North American study were taken as 0.2Mt CO_2/y/well. However in Europe the rates used for aquifers were 1 Mt CO_2/y/well based on Sleipner experience alone. If we take a typical 1000MWe coal fired power plant this would capture 6Mt/CO_2, in the European case you would need to drill and complete six wells to inject all the CO_2, whereas in the North American case you would need 30 wells plus the attendant bigger gas distribution system. Since the drilling and installation costs for wells are considered to be a major component of the net storage costs, it is clear that well injection rates are a critical component for any cost estimate for CO_2 storage[8].

Proximity of emission sources to storage opportunities and related transmission issues

The proximity of the emission sources to the main storage opportunities is shown in Figure 3.

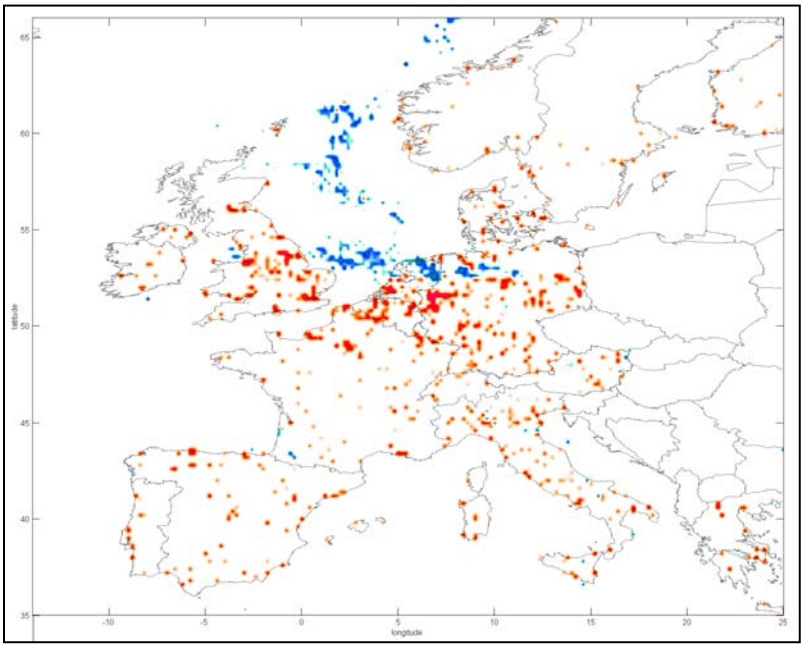

Figure 3. Geographical Relationship between Emission Sources and Storage Opportunities in Europe.

This clearly shows that most of the storage capacity in Europe lies off-shore in the Southern and Northern North Sea with some additional on-shore capacity in Northern Germany. Clearly, most of the

[7] The current exchange variation between the \$ and € did not exist in 2000 and therefore \$/t can be taken as €/t

[8] The European study undertook a sensitivity analysis on well injection rates for gas fields which indicated that the costs were very sensitive to changes in this parameter and could double for a 50% decrease in assumed well injectivity (see Figure 5.5 in main report)

storage capacity is well away from the clusters of large point sources shown earlier in Figure 2. This means that an extensive pipeline network will be required to transport the CO_2 from North-Central Europe to the North Sea. The impact of the transmission system on the costs of capture and storage are discussed later in this overview.

Impact of transmission requirements on storage costs in Europe

As discussed earlier, the study has identified that an extensive pipeline network will be required in Europe to transport the CO_2 from their point of origin to the storage opportunities in Northern Germany and the North Sea. To assess the impact of CO_2 transmission on the costs of CO_2 storage two types of transmission infrastructure systems were considered. In the first system, it was assumed that all individual sources will be connected to a reservoir that is sufficiently large to store its total emission of carbon dioxide for 20 years. In addition, it was assumed that the connection will be the cheapest option available, i.e. the combined costs for transport and storage for that specific source is the cheapest possible. In the second system, the construction of a large backbone (or "trunk" pipeline) was assumed. The total costs of the backbone and the costs of the satellite pipelines to the reservoirs determine the costs for backbone transport. Sources, which can be connected more economically individually to reservoirs, i.e. not using the transport capacity of the backbone, were allowed to do so.

Combined transmission and storage cost curves were then developed for two different sets of starting conditions. The first was a "2000-scheme", which considered current state-of-the-art technology for drilling and cost figures. The second was the "2020-scheme", which used anticipated technology and cost figures for 2020. A series of transport/storage scheme combinations were modelled, the details for all these schemes and the methodologies assumed in the construction of the cost curves is given in the main report and in the Appendices to the report. An example of the costs curve generated by one of the modelled schemes is given in Figure 4.

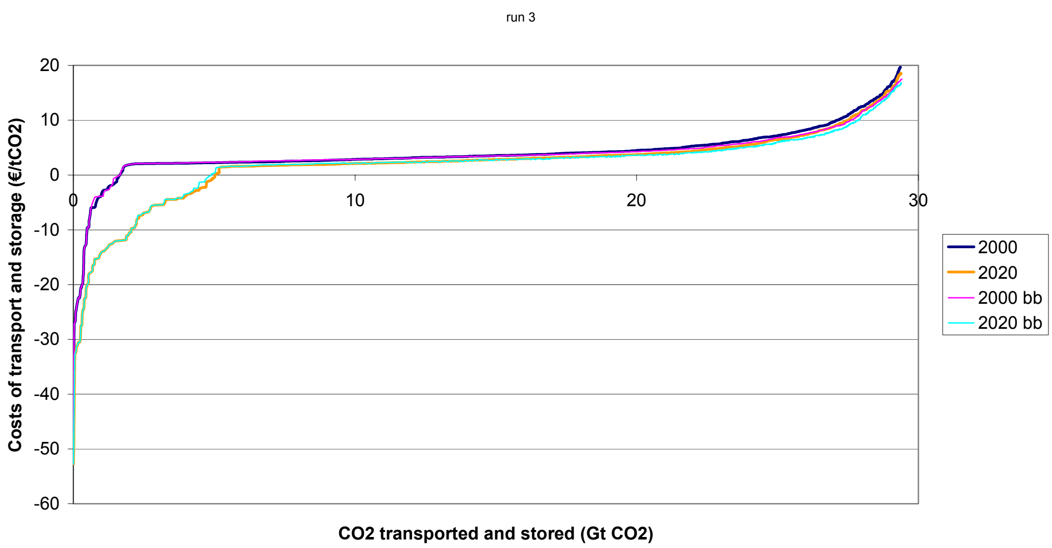

Figure 4. Example of Cost Curve for Transmission and Storage of CO_2[9]

The transmission scheme illustrated in Figure 4 assumed all types of storage structures were available for use both on and off-shore and CO_2-EOR was in operation in all oil fields. In total, 1 352 point sources were considered with a total emission of 30.7Gt over a 20 year period. In the non-backbone cases (donated by -2000 and -2020), 1073 point sources with a 20 year cumulative emission of 29.4Gt were connected to storage reservoirs in this scheme. The costs for transmission and storage were on

[9] Note: the cost curve calculations exclude costs above €20/t.

average €4.05/t CO_2 in 2000[10]. Including the backbone, meant that only 830 point sources with a 20 year cumulative emission of 29.6Gt were connected to a storage reservoir and the cost of transmission and storage was only marginally reduced to €3.95/tCO_2. Cumulative transport distances in both schemes were similar at 150,000 km[11]. In the back bone scheme, the back bone length would be 3231 km. Investment costs for the pipeline infrastructure were similar in both cases at €117-119 x10^3M.

It is noted that more lower cost capacity was observed in 2020 because it was assumed in the study that a number of hydrocarbon fields would not be available for storage purposes before 2020, bringing these on stream in 2020 provides additional opportunities for CO_2-EOR.

In only one modelled situation did a backbone scheme result in a reduced storage cost, this situation arose when only offshore hydrocarbon fields with EOR were considered for storage. In this case a cost reduction of around \$2/t CO_2 stored was observed. In this case less CO_2 is stored (11.4 Gt) compared to the previous case but total costs are also less (€56 x10^3M) because the pipeline lengths required to transport the CO_2 are lower.

Expert Group Comments

The draft report on the study was sent to a panel of expert reviewers and to a number of IEA GHG's members who had expressed interest in reviewing it. In general the comments received were not extensive and were generally typographical. However, two of the sets of comments received warrant further discussion. One reviewer asked for the draft report to be extended considerably to include more detail on the results of the transmission costs. The contractors included more detail in the main text and the supporting data provided as Appendices to the main report. The validity of the storage capacity estimates for deep saline formations developed in this study was questioned by one reviewer. In the study the storage capacities for these formations were estimated based on the areal[12] extent of the formation, it was suggested that this method grossly overestimates the capacity of such formations. It is acknowledged within the report that the quality of the data set on aquifers in Europe is poor, principally because these reservoirs have not been extensively researched or explored. Therefore due to the absence of data, and the fact that it was beyond the scope of the study to develop a more extensive geological dataset for these formations, the methodology was considered to be the best currently available for Europe.

[10] The current exchange variation between the $ and € did not exist in 2000 and therefore €/t can be taken as $/t.

[11] It is interesting to note that in the North American study the perception is that the sources are in close proximity to the storage opportunities and as a consequence large pipeline distances will not be required. If however, you compare the cumulative estimated pipelines lengths required (150,000 km in this study and 127,000 km in the North American study) they are similar.

[12] The term areal refers to the extent of the underground surface area of a geological formation extended to the surface.

Major Conclusions

The study has shown that there is an extensive storage capacity available within Western Europe, which is more than capable of storing most of Europe's emissions for several hundred years. CO_2 emissions in Europe have been observed to be clustered in several regions, notably in the industrial regions Netherlands, Germany and the UK. However, the potential storage capacity occurs mostly in deep saline formations that are principally situated in the North Sea. An extensive network of pipelines will, therefore, be required to match the emission sources with these storage opportunities in the North Sea. The study has shown that a significant investment will be required, close to €120 x10^3M, to construct the pipeline infrastructure needed to store Europe's CO_2 emissions in these off-shore formations. The infrastructure requirements raise the average cost of CO_2 storage from €1-3/tCO_2 to €4-5/tCO_2. An analysis of different transmission infrastructure schemes has indicated that when all storage opportunities are considered there are no significant cost savings in developing a transmission network with a trunk pipeline or back bone as opposed to allowing individual emission sources to match one to one with storage opportunities. However, there may well be social or regulatory issues that might drive the construction of a pipeline network rather than the construction of large numbers of smaller pipelines. Establishment of such a network will require a large upfront capital expenditure and most likely require some regulatory action or public sector financing to reduce the risk associated with the large early capital outlay.

A comparison of the net storage costs in this and the North American study has clearly shown that the storage costs are extremely sensitive to the number of wells that need to be drilled. In the North American study considerable experience is readily available from the extensive sub surface injection programmes underway in that region. However in Europe, data on injection rates into sub surface geological formations appears to be more limited. Taken together, the two studies are indicating that there is a range of storage costs (from \$3-12/t CO_2) depending on which well injection rates are used. It would seem that the greater uncertainty lies in the European injection rates because these are based on a single data point at Sleipner where CO_2 is injected into a highly permeable loosely packed sand formation. Whether comparable injection rates to those at Sleipner can be achieved in other formations in the North Sea can only be confirmed when more CO_2 injection operations take place in Europe and in particular in the North Sea.

Recommendations

One issue raised by the study is the need for more extensive research on the off-shore storage potential in deep saline formations for Europe. Whilst out of the scope of the IEA Greenhouse Gas R&D Programmes activities, it is recommended that an extensive research activity is needed to both collate exploration data, and where necessary supplement this data, on the North Sea deep saline formations. A detailed geological data set for all the formations that could be considered for storage in the future will be required. Such information will be essential before large scale injection of CO_2 in Europe into these reservoirs can be considered. It is acknowledge that some work is underway in Europe to determine the potential of off-shore fields through European Commission funded research projects like CO2STORE and CASTOR[13]. However, the work underway is limited to a few test cases whereas a much more extensive regional analysis is required covering the whole North Sea.

In addition, to help quantify the costs for storage in Europe more data on the injection rates that can be achieved into geological reservoirs is needed. The IEA Greenhouse Gas R&D Programme should consider an exercise to try and compare the injection data that is currently available in different formation types to determine if a correlation factor can be developed (if such a correlation does not already exist in the oil and gas exploration industry) which would be of immense practical value when extending these cost curve activities to other regions of the world where injection experience is limited.

[13] Details of these and other European Commission supported research projects can be found at www:co2captureandstorage.info

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Cost curves for CO_2 storage
Part 2: European sector

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Abstract

The current IEA GHG study is directed to the construction of cost curves for CO_2 transport and underground storage that are representative of OECD Europe.

In generating *cost curves* for transport and storage of CO_2 two types of transport infrastructure have been considered:
- Decentral transport infrastructure linking individual sources with individual storage structures (1-1 approach);
- Central main transport infrastructure linking more sources and storage structures (backbone approach).

The starting point for the generation of transport-storage cost curves is the emission of large European point sources over a period of 20 years, which amounts to about 30 Gt of CO_2. The cut-off value for the maximum costs is fixed at €20/tonne of CO_2 stored. When all storage structures are considered including the production of associated oil close to 100% of the 20-year emissions can be transported and stored at average costs of 4 €/tonne CO_2. The total costs amount to 119 billion euro. No cost reducing effect of the backbone was seen.
Not all emitted CO_2 can be stored when storage is restricted to the hydrocarbon fields: 53% without backbone and 67% with backbone. The costs per tonne CO_2 are higher, namely about 9 euro without backbone and about 8 euro with backbone.
The backbone transport infrastructure becomes more cost-effective when storage is restricted to offshore hydrocarbon fields. In this case the costs reduction with a backbone is more than 2 €/tonne CO_2.

The *storage capacity* of European deep saline aquifers is estimated at 150 to 1500 Gt of CO_2. The total capacity of hydrocarbon fields in OECD Europe is calculated at more than 40 Gt CO_2, 7 Gt of which can be stored in oil reservoirs. A technical (not economic!) evaluation of possible associated oil production resulted in an additional oil volume of about $2*10^9$ m^3, which is more than 10 billion barrels of oil. The storage capacity of European deep unminable coal seams at a depth of 800 to 1500 m is estimated at about 6 Gt CO_2. The presented storage capacities are associated with large uncertainties because of the lack of site-specific data.

The best *dataset* is available for oil and gas fields in Europe (uncertainty range of several factors), which is not surprising considering the effort that oil and gas industry put in exploiting European hydrocarbon resources. The quality of the available datasets for European deep saline aquifers and deep unminable coal seams is far less (uncertainty range of one order of magnitude).

Contents

1 Introduction

1.1 Background

The IEA Greenhouse Gas R&D Programme (IEA GHG) has been systematically evaluating the cost and potential for reducing emissions of greenhouse gases arising from anthropogenic activities, especially the use of fossil fuels. A mitigation technology that has been given particular attention is the capture and storage of CO_2 originating from large stationary point sources. To date a series of studies have been undertaken, on a range of options for the storage of carbon dioxide.

1.2 Objective

The objective of the current study is to build cost curves for the underground storage options that are present in the OECD countries of Western Europe (see Appendix A). The storage options that are included are:

- Storage in deep saline aquifers
- Storage in depleted/disused oil and gas fields
- Storage in oil fields combined with oil production
- Storage in deep unminable coal seams with coal-bed methane production

The cost curves will account for the expenditures that are related to the storage itself and to transmission of CO_2.[1]

1.3 Approach

Cost curves are constructed for the transport of carbon dioxide from the capture site to a geological structure, in which it is stored, and for the underground storage. Cost of capture and compression are NOT included in the costs curves. The cost curves are developed for two different sets of starting conditions. The first set of starting conditions, which is indicated by the term "**2000-scheme**", refers to the current situation, i.e. current state-of-the-art technology for drilling and cost figures as are known today, and storage structures, which are available today or will become available before 2020. In the calculations done with the second set of starting conditions, which is indicated by the term **"2020"-scheme**, the anticipated technology and cost figures as may be available in 2020 are taken. In this scheme, it is assumed that all storage structures are available. It should be stressed that the cost curves do not represent a projection of future transport and storage activities but rather a graphical representation of the transport and storage opportunities ordered from the lowest costs to the highest costs under (cost) conditions that may be present now or somewhere in the future.

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[1] Costs are presented in euro for the reference year 2000 (parity between euro and USD is assumed). Projections for the cost development in 2020 have also been provided.

1.4 Data availability and collection

Compiling data on geological reservoirs for CO_2 storage and determining the technical storage capacity of these reservoirs form the first steps in developing the cost curves for each storage option. This data, along with available data on CO_2 sources (IEA GHG & Ecofys, 2002; Hendriks, 2003), is input into a Geographic Information System (GIS), which allows the distances between the sources and the storage reservoirs to be determined so that the cost for transmission of CO_2 can be derived.

The necessary data are provided by earlier studies that were performed for the EC and the IEA GHG R&D Programme. A survey of the geological reservoirs that could be used for geological storage of CO_2 was completed for 12 EU countries as part of a European Commission (EC) supported JOULE study in 1996 (ed. Holloway)[2]. In 2003 a more rigorous mapping exercise for 8 EU countries using GIS in Europe was finished under the GESTCO project (eds Christensen & Holloway)[3]. A database of CO_2 sources was developed in the IEA GHG study (IEA GHG, 2002; Hendriks, 2003). A limited additional inventory was performed to complete a representative dataset for the whole of OECD Europe (see Appendices B-D).

Acknowledgement

The authors wish to thank Roberto Bencini of IGNV, Italy for providing invaluable data on the location of oil and gas wells in Italy. The constructive comments of the three anonymous reviewers are very much appreciated.

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2 The Joule II project was completed in 1996. It examined the potential for reducing industrial CO_2 emissions to the Earth's atmosphere by storing it underground. The report concluded that this could probably be done practically, safely and economically, with minimal effects on man and the natural environment. As part of this project an inventory was made of the CO_2 storage capacity of the then 12 EU countries and Norway. This inventory was used in the construction of the CCC-EUR database.

3 The GESTCO project was concluded in 2003. It examined whether it would be practical to spread CO_2 Capture and Storage technology similar to that deployed at the Sleipner gas field to major industrial plant throughout the European Union and Norway. Some detailed case-studies of CO_2 storage in selected settings around Europe were undertaken. The results of some of these studies are included in the CCC-EUR database. The following 8 countries were covered in the inventory of storage potential in the GESTCO project: Norway, Denmark, Great Britain, Germany, The Netherlands, Belgium, France and Greece.

2 CO_2 storage structures and their capacity

The following storage options have been studied:
- Deep saline aquifer
- Hydrocarbon field
- Oil field with incremental oil production
- Deep unminable coal seams with CH_4 production

For each storage option, the available data, calculation method and storage capacity will be presented. The gathered data have been stored in a GIS database (BGS).

Uncertainty
The presented numbers for the storage capacity are associated with significant uncertainties, in particular for the aquifer option. Because site-specific data were missing, the estimates had to be based on simple calculations with quite a number of assumptions.

2.1 Deep saline aquifers

2.1.1 Data inventory

The data on saline aquifers from the GESTCO project cover a restricted number of countries in OECD Europe[4] and are of markedly different levels of detail. In order to present a comprehensive overview of the storage capacity of saline aquifers in OECD Europe we generated a new low-level dataset covering the whole of OECD Europe. Two other datasets with higher levels of detail were also compiled, but these additional datasets are not comprehensive, covering only those parts of OECD Europe where data were readily available. They are useful to verify the storage capacity calculated from the low level comprehensive dataset.

The collected data on saline aquifers has been subdivided into three levels:

Aquifer data level 1 (lowest level)

This shows locations of sedimentary basins that may have potential for CO_2 storage (Figure 2.1). It is recognised that as well as the reservoir rocks that occur in these sedimentary basins, there are reservoir rocks which may have storage potential *beneath* some of them, for example below the Cenozoic Molasse Basin in Austria, Germany and Switzerland.

Level 1 data is available for the whole of OECD Europe. Data south of 62°N has been displayed in the GIS. This cut-off has been used because the area north of 62°N is remote from most of the large industrial point sources of CO_2 in OECD Europe. Furthermore, more detailed data from Norway, the only OECD Europe country with significant potential north of 62°N is available (Bøe et al. 2002).

[4] In the GESTCO-project the aquifer storage potential was determined for specific areas in several countries: Norway, Great Britain, Denmark, Germany, The Netherlands, Belgium, France and Greece.

Not all sedimentary basins have been included because some are too remote from major point sources of CO_2.

The level 1 data were used to calculate the storage capacity.

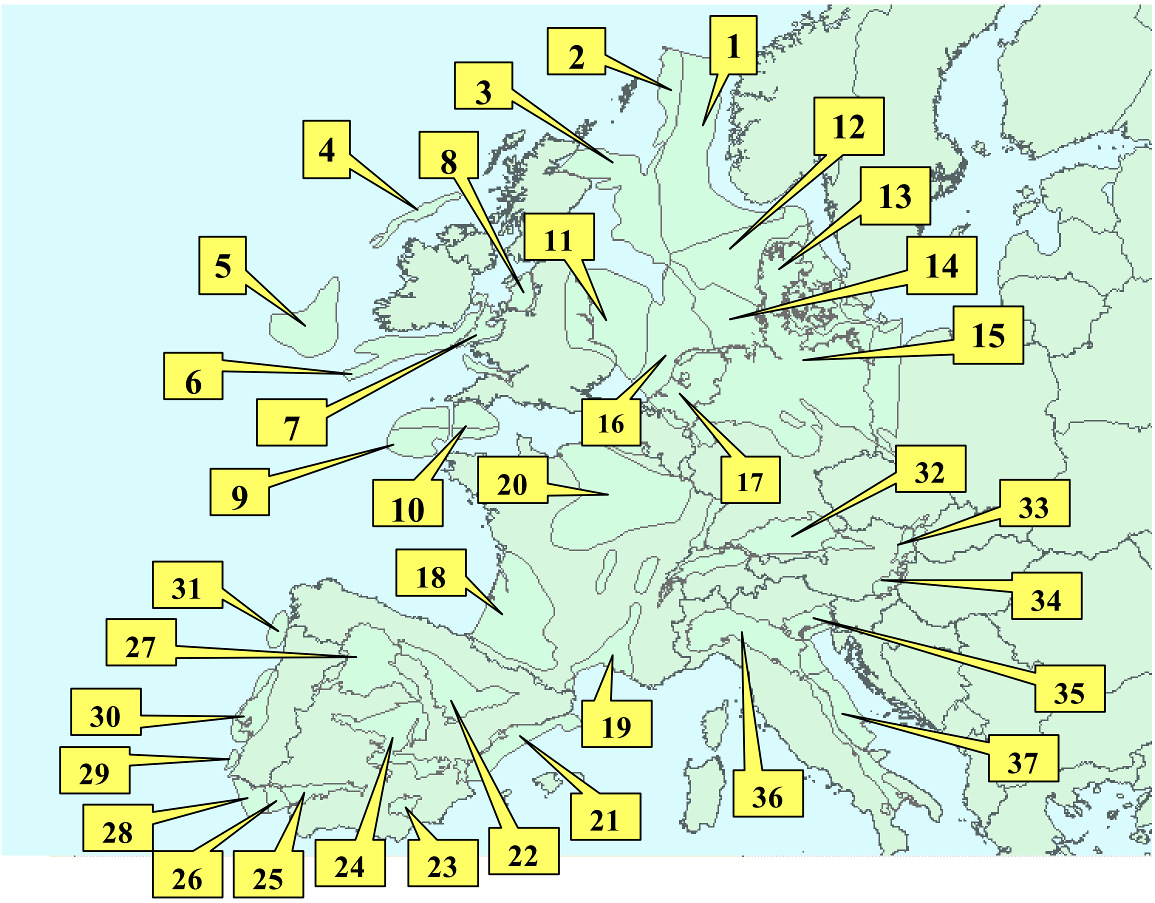

Figure 2.1 Distribution of sedimentary basins with possible CO_2 storage potential
Key: 1 Norwegian North Sea, 2 UK Northern North Sea, 3 UK Central North Sea, 4 Slyne Basin, 5 Porcupine Basin, 6 Celtic Sea Basin, 7 St George's Channel/Cardigan Bay Basin, 8 East Irish Sea Basin, 9 S W Approaches Basin, 10 Western Channel Basin, 11 UK Southern North Sea Basin/Onshore Eastern England, 12 Danish North Sea, 13 Onshore Denmark, 14 North German Basin offshore, 15 North German Basin, 16 Offshore Netherlands, 17 Onshore Netherlands, 18 Aquitaine Basin, 19 Rhone Basin (with N Rhone Basin to N and Limage Basin to NW), 20 Paris Basin, 21 Gulf of Valencia Basin, 22 Ebro Basin, 23 Campo de Cartagena Basin, 24Madrid Basin, 25 Guadalquivir Basin, 26 Gulf of Cadiz Basin, 27 Duero Basin, 28 Algarve Basin, 29 Alentejo Basin, 30 Lusitania Basin, 31Porto Galicia Basin, 32 Molasse Basin, 33Vienna Basin, 34Styrian Basin, 35 Veneto basin, 36Po Basin, 37 Central Adriatic/Apulia Platform.

The locations of the major deep sedimentary basins in OECD Europe were digitised and added to the GIS database. Where a basin occurs in more than one country or is partly offshore and partly onshore, it has been subdivided into polygons corresponding to the area of the basin that is onshore or offshore in each individual country. Thus the area of the basin onshore and offshore in each country can be measured. The distinction between offshore and onshore parts of the basin is made because potentially it affects the economic analysis. Sedimentary basins were cut into smaller parts, each of which is referred to with a single aquifer injection point.

Deep saline aquifer data level 2 (medium level)

This data shows the areas of sedimentary basins where the basin floor is below 700 m and therefore potentially suitable for CO_2 storage in the dense phase. Level 2 data, which is not available for all basins, has been stored in the GIS database as well (BGS).

Deep saline aquifer data level 3 (highest level)

This provides details of individual deep saline aquifers within a sedimentary basin that may have potential for CO_2 storage. Data is not available for all basins and not necessarily for all deep saline aquifers within a basin. Level 3 data is shown in tables but the distribution of the individual deep saline aquifers is not shown on the GIS because it is not available for many deep saline aquifers.

Much of the detailed data at Level 3 is derived from previous studies (principally the Joule II study (Holloway, 1996), updated where appropriate by the GESTCO study).

A higher level of detail above level 3 could be defined for the characterisation of individual deep saline aquifer traps (e.g. Bunter sandstone study of Brook et al., 2002) or deep saline aquifer storage sites, but this was clearly beyond the scope of the present study.

A review of the deep saline aquifer data outside the study areas of the GESTCO and the Joule II projects can be found in Appendix B.

2.1.2 Calculation method (data level 1)

There is no unique solution to the problem of how to calculate the CO_2 storage capacity of deep saline aquifers, because of the highly variable nature of the subsurface (and other factors) at any particular locality (e.g. Obdam et al., 2003). For example, different trapping mechanisms may be dominant and different injection strategies may be needed. Thus it is not realistic to apply a single consistent calculation methodology to the whole of a large geographical region such as OECD Europe. Nevertheless, a crude attempt to calculate the storage capacity needs to be made in order to scope the potential for storage and to construct marginal abatement cost curves.

In this study different methods have been identified to calculate the CO_2 storage potential of deep saline aquifers depending on the level of information available (see Appendix E). As the level of information increases, increasingly sophisticated calculations can be made. However, it should be emphasised that for deep saline aquifers, CO_2 storage calculations should really be made on a case-by-case basis if they are to be considered realistic. Indeed, Obdam et al. (2003) states that no estimate of CO_2 storage capacity of a reservoir can be made without reservoir simulation. However, it should be emphasised that the necessary data to make realistic CO_2 storage capacity estimates for the deep saline aquifers in many of the sedimentary basins is simply not available. At present, there are few if any such calculations that can be extrapolated to even a single sedimentary basin to give quality assurance to the methods of calculation used here.

Assumptions

The level 1 data at basin scale level have been used for storage calculations, because at this low level the inventory is geographically complete. The chosen principle for the estimation of the storage capacity in areas with a very low information level is that the surface area of a basin is considered to be proportional to the storage capacity of that basin. Given the limitations of the available dataset, it seems reasonable to assume that a large basin may have more well sealed pore space than a small one. In the absence of more detailed evidence it has been assumed that only one reservoir is present in each level-1 basin, and that this reservoir covers 50% of the area of the basin and is well sealed throughout.

Three storage hypotheses have been considered:
1. Unconfined aquifer storage hypothesis: There is no significant pressure build-up in the reservoir; the aquifer behaves as if its horizontal extension is infinite. Van der Meer (1996) performed reservoir simulations of an infinite aquifer, which resulted in an averaged storage potential of 2 Mt CO_2/km^2. This situation is comparable to the situation at the Sleipner CO_2 injection site where hardly any pressure build-up is noticed.
2. Confined aquifer storage hypothesis: The aquifer is assumed to be an isolated container-like system. The storage space is created by the matrix and pore compressibility, which creates storage space (see Holloway, 1996: p. 181).
3. CO_2 dissolution hypothesis: It is assumed that all CO_2 effectively dissolves in the water column up to the maximum saturation level (see also Bruant et al., 2002).

Table 2.1 lists the assumed storage capacities per km^2 for the individual storage hypotheses. The analysis of storage costs is based on the confined aquifer hypothesis, which is considered to be the most conservative one in terms of storage capacity.

Table 2.1 The various deep saline aquifer storage hypotheses and assumed storage capacities per km^2; assumed aquifer thickness = 100 m.

	Storage hypothesis	CO_2 storage factor [Mtonnes / km^2]
1.	Unconfined aquifer	2.0
2.	Confined aquifer	0.2[5]
3.	CO_2 dissolution concept	0.6[6]

[5] The assumptions for the estimated areal storage capacity nr 2 are: thickness aquifer = 100 m, N/G-ratio = 0.8, porosity = 0.2, $\rho CO2$ = 700 kg/m^3, storage efficiency = 0.02.

Equation

The CO_2 storage potential in deep saline aquifers is calculated as follows:

$V_{CO2} = A \times ACF \times SF$

with:

V_{CO2}	=	CO2 storage capacity [Mtonnes]
A	=	area of the basin [km^2]
ACF	=	aquifer coverage factor [-]
SF	=	storage factor, [Mtonnes / km^2]

The aquifer coverage factor (ACF) is assumed to be 0.5. The storage factor (SF) depends on the storage concept (see Table 2.1).

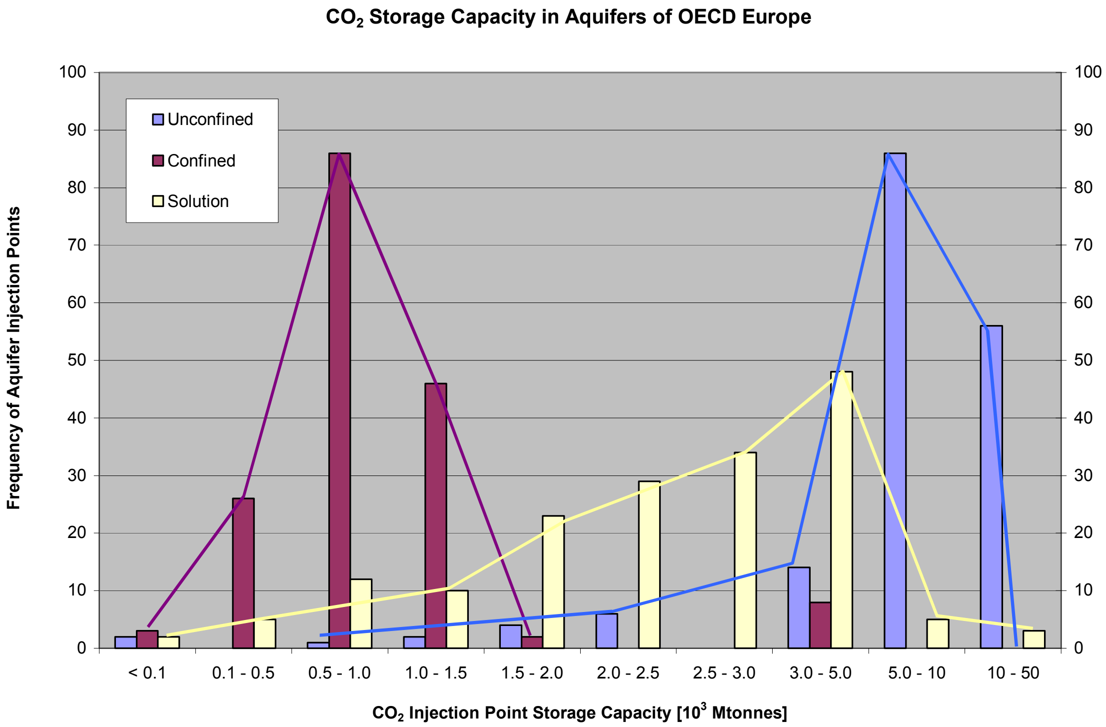

Figure 2.2 Calculated storage capacity of deep saline aquifers in Europe (OECD), per size class of aquifer injection points for three different storage hypotheses.

[6] The assumptions for the estimated areal storage capacity nr 3 are: thickness aquifer = 100 m, N/G-ratio = 0.8, porosity = 0.2, solubility = 40 kg/m^3 H_2O.

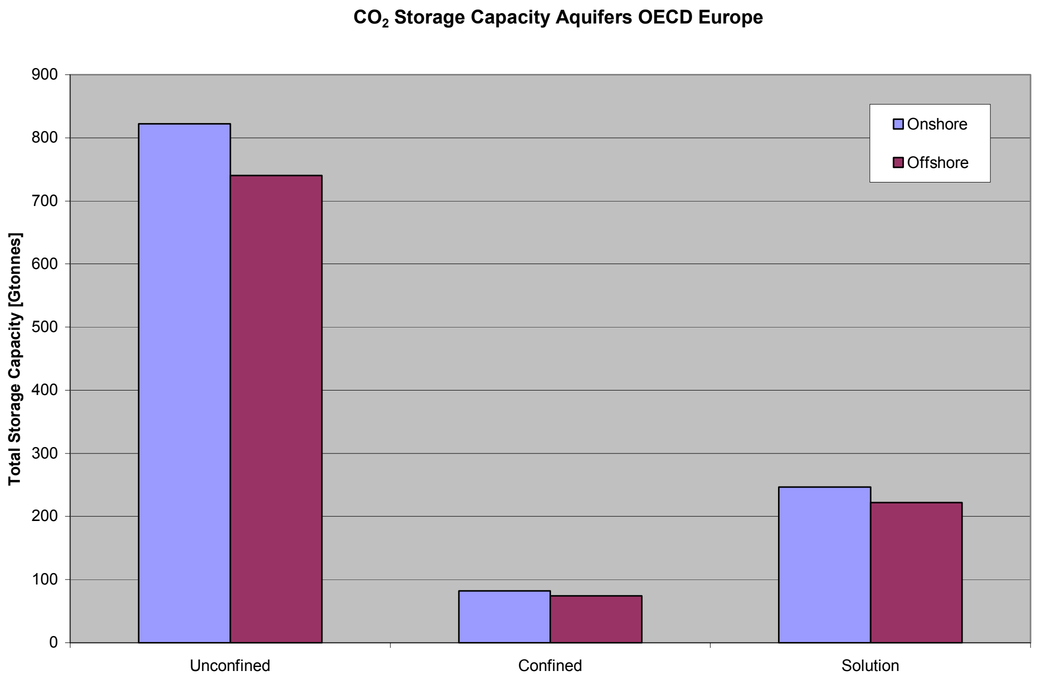

Figure 2.3 Total onshore and offshore storage capacity of deep saline aquifers in Europe (OECD) for the three aquifer storage hypotheses.

2.1.3 CO_2 storage capacity

The storage potential in deep saline aquifers is significantly larger compared to those in coal (Section 2.4.3) and hydrocarbon fields (Sections 2.2.3 & 2.3.3). Figure 2.2 shows the storage capacity for three aquifer storage hypotheses. The total onshore and offshore storage capacity is about similar as is shown in Figure 2.3.

2.2 Hydrocarbon fields

2.2.1 Data inventory

The GESTCO-project has resulted in an already well-integrated dataset for hydrocarbon fields in the North Sea region, to which data from the Joule II project have been added. Additional inventories have been performed for: Austria, Ireland, Italy, Portugal, Spain and Switzerland (Appendix C).

2.2.2 Calculation method

The concept of CO_2 storage in depleted oil and gas reservoirs is that the recovery of hydrocarbons creates space to store CO_2. Like previous storage inventories (e.g. GESTCO project, JOULE II project) it is assumed that the entire underground volume of ultimately recoverable hydrocarbons can be replaced by CO_2.

The main parameters to determine the CO_2 storage potential are the ultimate recovery, formation volume factors of oil (Bo) and gas (Bg) and the CO_2 density (ρ_{CO2}) at reservoir conditions. The latter three parameters are pressure and temperature dependent. In addition, the Bo and Bg also depend on the hydrocarbon composition of the reservoir fluid, which is different for each field. Average in-situ reservoir conditions are required to calculate the CO_2 storage capacity.

Assumptions

Note that field-specific data, such as the Bo, Bg and ρ_{CO2} are not given for all hydrocarbon occurrences because of constraints on the public availability of data from country to country. Often, only the average reservoir depth and the ultimate volume of recoverable hydrocarbons are provided. In this case, average reservoir pressure and temperature can be estimated under the assumption that normal gradients can be applied. These yield 0.03 °C / m and 0.0105 MPa / m. The Bg could be estimated from the pressure and temperature assuming a hydrocarbon composition of 100% methane (Batzle and Wang, 1992) If the Bo is not given, the Bo is assumed 1.2 BBL_{res} / BBL_{stp}. In case the ρ_{CO2} is not given, a value of 700 kg / m^3 at reservoir conditions is applied to calculate the CO_2 storage capacity. No significant water-influx is assumed.

Uncertainty

A number of uncertainties are associated with the estimated storage capacities of hydrocarbon fields. The estimate of the maximum storage capacity can be several factors higher than the estimate of the minimum storage capacity. A discussion of the uncertainty in calculated storage capacities can be found in Schuppers et al. (2003).

Equations

A generally accepted formula to calculate the CO_2 storage capacity of an oil field is:

$$V_{CO2} = (Voil_{(stp)}/1000) \times Bo \times \rho_{CO2}$$

and for a gas field:

$$V_{CO2} = Vgas_{(stp)} \times Bg \times \rho_{CO2}$$

with:

V_{CO2}	=	CO_2 storage capacity [Mtonnes]
$Voil_{(stp)}$	=	volume of ultimate oil recovered at standard conditions [10^6 m^3]
$Vgas_{(stp)}$	=	volume of ultimate gas recovered at standard conditions [10^9 m^3]
Bo	=	oil formation volume factor [-]
Bg	=	gas formation volume factor [-]
ρ_{CO2}	=	density of CO_2 at reservoir conditions [kg / m^3]

In case both oil and gas are present as separate phases in the hydrocarbon field ("combi-field"), the V_{CO2} for oil and gas are added. Condensate fields are treated as gas fields to calculate the CO_2 storage capacity. If an oil field produces a certain volume of gas, this volume is accounted for by the Bo and will be treated as solution gas in the oil phase.

2.2.3 CO_2 storage capacity

The CO_2 storage capacity for hydrocarbon fields in Europe is presented in Figure 2.4. The majority of hydrocarbon fields have a storage capacity less than 50 Mtonnes of CO_2. For the cost-curve calculation, hydrocarbon fields with a storage capacity of less than 4 Mtonnes are excluded from further analysis.

Individual hydrocarbon fields with an individual storage capacity of less than 4 Mt CO_2 add insignificantly to the overall capacity of European hydrocarbon fields. Furthermore, a storage capacity of 4 Mt CO_2 with a lifetime of 20 years implies an annual storage capacity of 0.2 Mt CO_2, which a priori is considered to be uneconomical.

Figure 2.5 presents the relative frequency distribution of hydrocarbon fields in Europe. Relatively, the oil fields have the highest number of fields with a small CO_2 storage capacity.

The cumulative CO_2 storage capacity for the oil, gas and combined oil/gas fields are presented in
Figure 2.6. Fields with a capacity smaller than 4 Mtonnes are excluded. The total storage capacity of the hydrocarbon fields in Europe is 41 Gtonnes CO_2.

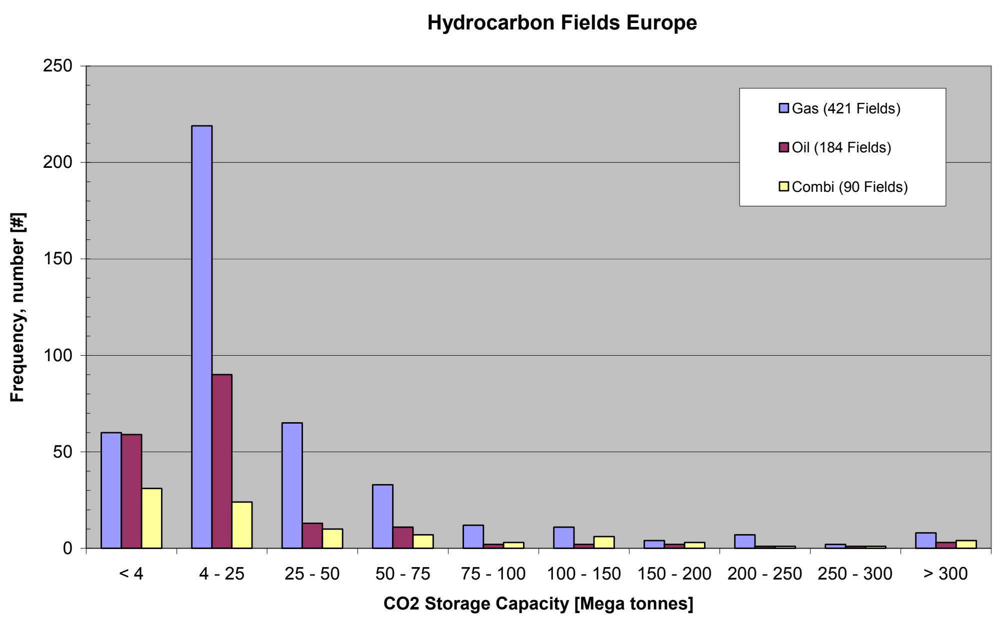

Figure 2.4 Storage capacity of hydrocarbon fields in Europe per size class; Combi = combined oil/gas field.

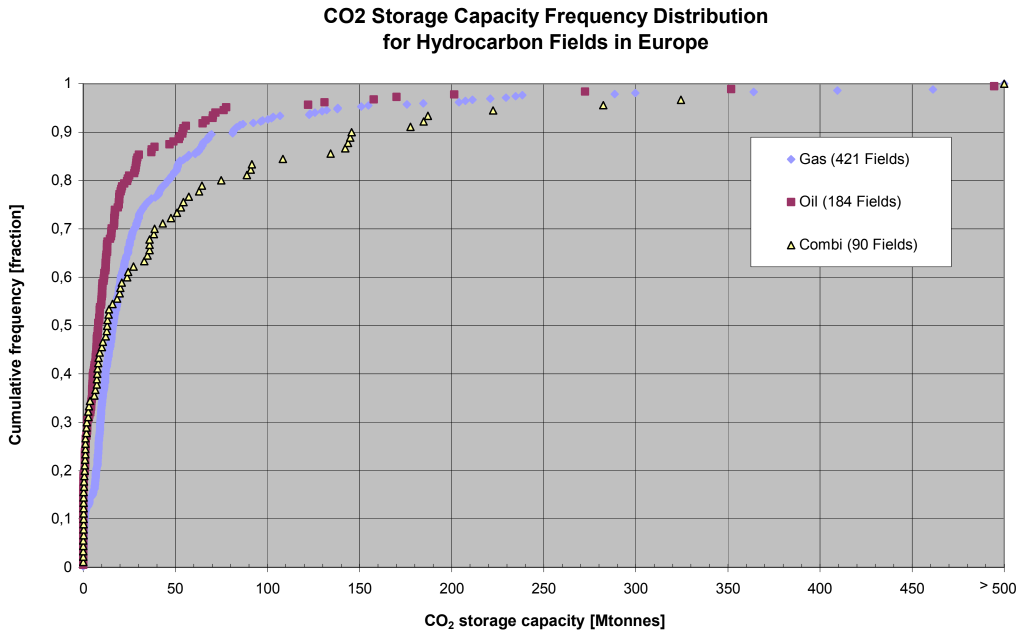

Figure 2.5 Frequency distribution of CO_2 storage capacity of hydrocarbon fields in Europe; Combi = combined oil/gas field.

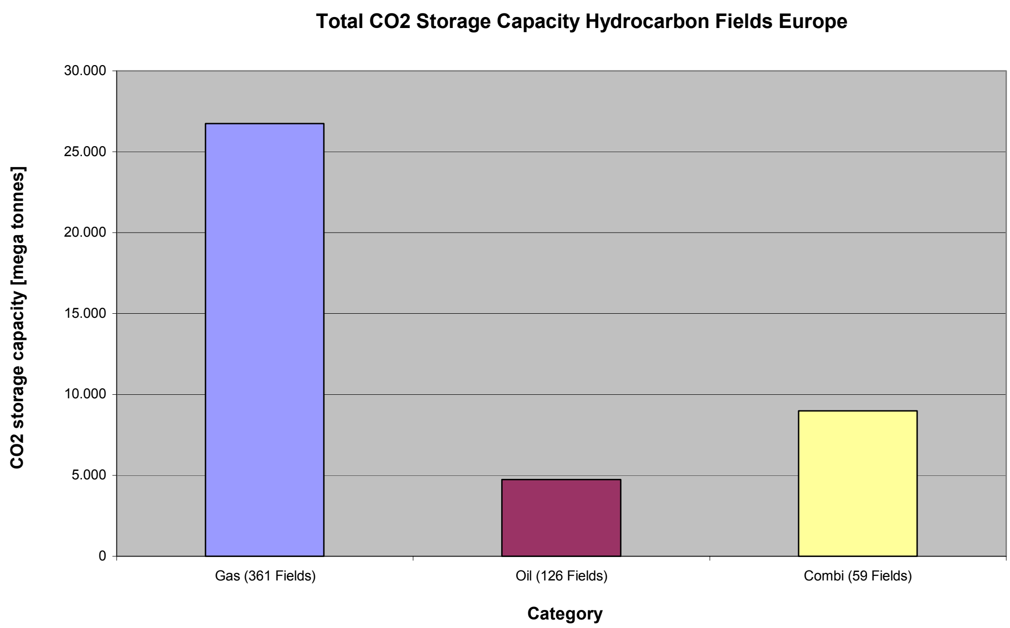

Figure 2.6 CO_2 storage capacity in gas, oil and combined gas/oil fields of OECD Europe.

2.3 CO_2 storage and oil production

CO_2 is an auxiliary material for increasing oil production through lowering the viscosity of oil if it is miscible with oil or through increasing the sweep efficiency if not miscible with oil. Thus CO_2 storage could have an additional economic value through incremental oil production. Since the mid seventies, CO_2 injection has been applied to oil fields in the US for enhancing economic oil production, also known as Enhanced Oil Recovery (EOR).

2.3.1 Inventory

The data for calculation of the storage capacity and incremental oil production are the same as have been used for the oil fields and the oil reserves in the combined oil/gas fields in Section 2.2. Additional information has been gathered for the calculation of the incremental oil production. e.g. the API gravity (Table 2.2).

Table 2.2 Estimate of average API oil gravity for individual countries (modified after Hendriks et al., 2002).

Country		API gravity
Austria	AT	40
Germany	DE	28
Denmark	DK	28
France	FR	42
Greece	GR	42
Italy	IT	20
Netherlands	NL	28
Norway	NO	42
Spain	ES	42
United Kingdom	UK	40

2.3.2 Calculation method

It is assumed that the total amount of CO_2 that can be injected in an oil field or combined oil/gas field in combination with incremental oil production equals the storage capacity that has been calculated for depleted oil fields and oil reserves in combined oil/gas fields (Section 2.2). This is considered to be a conservative approach. In contrast to Section 2.2, the storage capacities of oil fields and of the oil reservoirs in the combined oil/gas fields have been lumped.

Quite a number of uncertainty sources are associated with the estimation of storage capacity and incremental oil production (see also Section 2.2).

The difference to the cost curve calculation for depleted oil fields and combined oil/gas fields is that here extra revenues can be addressed to the incremental oil production as a consequence of CO_2 injection. This requires an estimate of the incremental oil production.

Equations

The CO_2 storage capacity in fields where incremental oil production can be applied is thus calculated similarly to the calculation of oil fields and oil reserves in combined oil/gas fields:

$V_{CO2} = (Voil_{(stp)}/1000) \times Bo \times \rho_{CO2}$

with:

V_{CO2}	=	CO_2 storage capacity [Mtonnes]
$Voil_{(stp)}$	=	Volume of ultimate oil recovered at standard conditions [10^6 m^3]
Bo	=	Oil formation volume factor [-]
ρ_{CO2}	=	Density of CO_2 at reservoir conditions [kg / m^3]

The amount of additional oil that will be produced as a result of the CO_2 injection is estimated from the equations firstly applied by Stevens et al. (1999) and is based on an empirical relationship between API gravity and EOR recovery. The equations require the original oil in place (OOIP) of the field and the API oil gravity. These parameters were not available in this study and had to be estimated.

The OOIP is estimated from the equation by Stevens et al. (1999):

$OOIP = Voil_{(stp)} \times ((API + 5) / 100)^{-1}$

with:

OOIP	=	original oil in place [10^6 m^3]
$Voil_{(stp)}$	=	volume of ultimate oil recovered at standard conditions [10^6 m^3]
API	=	API oil gravity [°]

The extra oil due to the enhanced oil recovery is determined as:

$EOR = (\%X / 100) \times C \times OOIP$

with:

EOR	=	extra oil due to enhanced oil recovery by CO2 injection [10^6 m^3]
%X	=	percentage of extra oil recovery due to CO2 injection [%]
C	=	contact factor accounting for the % of oil in contact with CO_2 [-]
OOIP	=	original oil in place [10^6 m^3]

The contact factor (C) is assumed to be 0.75 for every field. This is a conservative assumption (Hendriks et al., 2002). The percentage of extra oil (%X) due to CO_2 injection is a step function based on EOR project experience and depends on the API oil gravity (Figure 2.7).

Figure 2.7 Relation between API gravity and percentage of incremental oil production due to CO_2 injection.

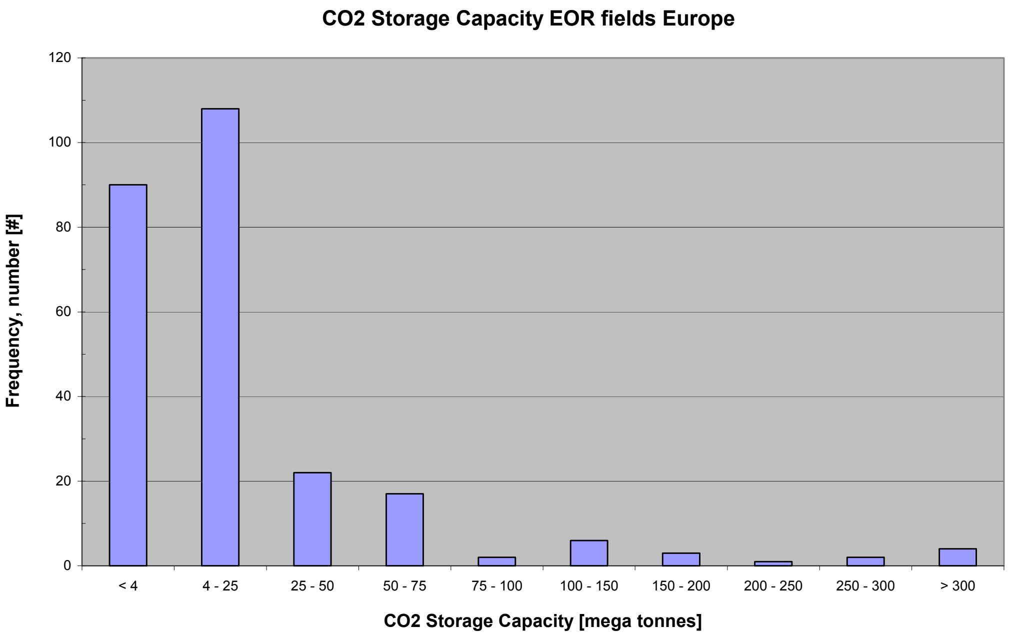

Figure 2.8 Number of oil fields and combined oil/gas fields for incremental oil production in OECD Europe per class of CO_2 storage capacity.

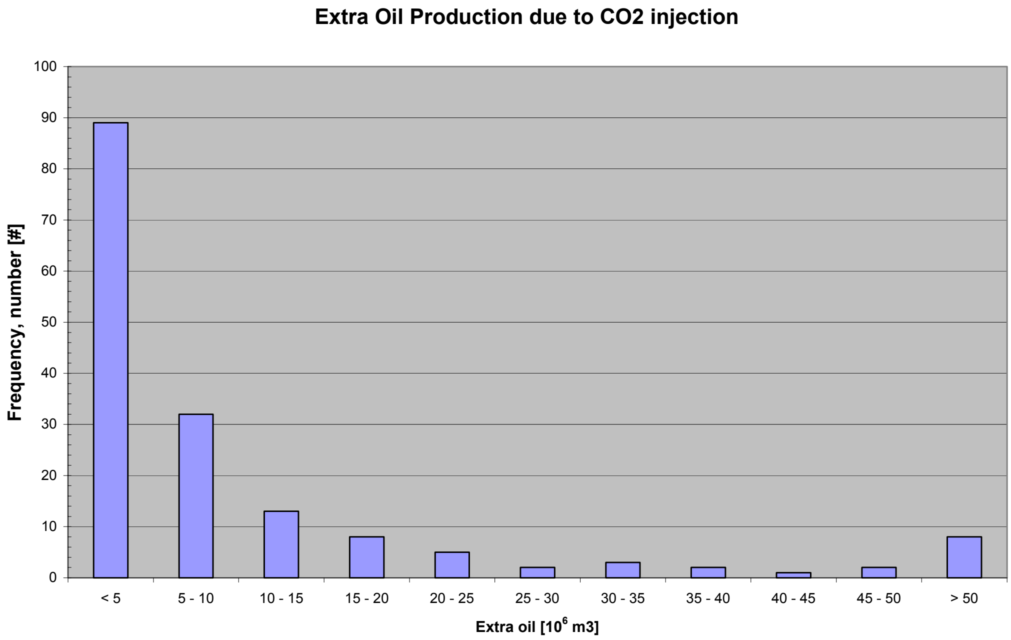

Figure 2.9 Number of oil fields and combined oil/gas fields in OECD Europe per size class of incremental oil production as a result of CO_2 injection.

2.3.3 CO_2 storage capacity and oil production

The CO_2 storage capacity in the oil column of combined oil/gas fields is added to the storage potential in oil fields (Figure 2.8). The total CO_2 storage capacity of EOR fields in Europe is 7 Gtonnes CO_2. Fields with a capacity smaller than 4 Mtonnes CO_2 have not been included in this number (see Section 2.2.3).

Figure 2.9 presents the extra oil recovery that is gained due to the injection of CO_2. The cumulative amount of extra oil production is $2*10^9$ m^3.

2.4 CO_2 storage and coal-bed methane production

Principally, CO_2 sorption onto coal is considered possible in deep unminable coal seams that are not fully saturated with methane or as part of an enhanced coal-bed methane (ECBM) project where the CO_2 displaces the methane that was sorbed by the coal.

Limited experience exists with CO_2 storage in ECBM projects, which invokes uncertainty in the following factors:

- Accessible coal factor, i.e. the area that could be used safely for CO_2 injection combined with the part of the net cumulative coal thickness within the drilled strata that will contribute to the gas production. The area suitable for CO_2 projects is less than the total areal extent of the coal because of the presence of mine shafts,

faults or other geologic features that may form escape routes for CO_2 towards the surface near the project.
- Exchange ratio, i.e. the average number of CO_2 molecules that replace one gas/methane molecule.
- Recovery factor, i.e. the amount of gas/methane that can be produced from a contributing coal seam relative to the total gas in place.

2.4.1 Inventory

The starting-point for the inventory is the work in the GESTCO project for the Netherlands, Belgium, United Kingdom and France. Additional inventories have been performed for the following countries: Austria, Ireland, Italy, Portugal, Spain and Switzerland. The inventory of black coal seam data was not performed for Germany, because there was doubt about the seal integrity of the overburden in the German black coal mine districts.

Criteria for coalfields that are suitable for CO_2 storage by sorption onto coal are:

- Depth is the most important parameter to determine how much CO_2 could be absorbed onto coal. Many coal properties depend on the in-situ pressure and temperature of the coal layers. A minimum depth of 800 meters was chosen because coals above this depth are presumed to have priority for mining rather than CO_2 sequestration (the two activities being mutually exclusive). Note that much of the coal in OECD Europe above 800 m has already been mined or affected by mining of adjacent seams. This may lead to the creation of escape pathways for CO_2 via exploration boreholes mine shafts and roadways, collapsed workings and subsidence. Below 1500 meters the permeability of the coal seams in Europe is assumed to be too low for CO_2 injection and CBM production. In this study the storage potential in coal layers between 800 and 1500 meters of depth have been evaluated.

- Coal layers with a minimum seam thickness of 40 cm were inventoried. Smaller seam thickness is considered uneconomical because of the limited injection rate and storage capacity.

- Coals of lignite and anthracite rank were excluded because the possibility of CO_2 storage in this coal type is still questionable.

Most information about coal layers is related to regions where coal is or was actively mined down to a depth of about 700 m. For this reason the extent and thickness of coal layers in the subsurface deeper than 800 m is not known in great detail. Current information is based on extrapolations of shallower data down to larger depths combined with a limited number of coal exploration wells and seismic data.

Spurious data are available on the following properties of the coal layers:
- depth and thickness (see also Figure 2.11);
- permeability of coal;
- density of coal;
- gas/methane content;

2.4.2 Calculation method

The following assumptions for the CO_2 storage calculation and the producible coal-bed methane-in-place have been made:

Assumptions

- Homogeneous properties of coal layers
- Permeability and injection rate large enough to be economically attractive
- The following numbers apply:
  - ρ_{coal} = in-situ density of the coal [1350 kg / m^3]
  - GC = gas content of coal [0.008 m^3 gas_{stp} / kg coal]
  - ACF = accessible coal factor [0.5]
  - ER = exchange ratio of CO_2 for methane [2.5]
  - RF = recovery factor [0.4]
  - ρ_{CO2} = density of CO_2 [1.977 kg / m^3_{stp}]

A number of uncertainties are associated with the assumptions underlying the estimated storage capacities of coal fields. An uncertainty analysis of storage capacity in Dutch coal fields revealed that the uncertainty range can equal up to one order of magnitude or more (Van Bergen & Wildenborg, 2003).

Equations

A generally accepted formula to calculate the Gas-In-Place (GIP) reserves is the following:

$$GIP = A \times h \times \rho_{coal} \times G_c$$

with:

GIP = gas-in-place [10^6 m^3_{stp}]
A = area [km^2]
h = cumulative height of coal in the area [m]
ρ_{coal} = density of the coal [kg / m^3]
Gc = gas content of coal [m^3 gas_{stp} / kg coal]

More important than the current total amount of gas present, is the amount of CH_4 that can be produced from the deep unminable coal seams and the amount of CO_2 that can take its place. The equation is extended with the recovery factor, to get:

$$PGIP = GIP \times ACF \times RF$$

with:

PGIP = producible-gas-in-place [10^6 m^3_{stp}]
ACF = accessible coal factor [-]
RF = recovery factor [-]

The amount of CO_2 that can be stored is calculated by the following equation:

$$CO_2S = PGIP \times ER \times \rho_{CO2} \times 10^{-9}$$

with:

CO_2S	=	amount of CO_2 to be stored [Mtonne]
PGIP	=	producible-gas-in-place [10^6 $m^3{}_{stp}$]
ER	=	exchange ratio of CO_2 for methane [-]
ρ_{CO2}	=	density of CO_2 [kg / $m^3{}_{stp}$]

2.4.3 Storage capacity and coal-bed methane production

The CO_2 storage capacity for the deep unminable coal seams in Europe is presented in Figure 2.10, based on the above assumptions and equations. In case the thickness and/or depth of the deep unminable coal seams were not given, average values of the country have been applied. The majority of the fields have an individual capacity, which is smaller than 50 Mtonne CO_2. Deep unminable coal seams with a storage capacity of less than 1 Mtonne are not included in this figure.

The total storage capacity of coal fields with an individual capacity of less than 1 Mt contributes insignificantly to the overall storage capacity of European coal fields. Furthermore, a storage capacity of 1 Mt CO_2 for deep unminable coal seams with a lifetime of 20 years implies an annual storage capacity of 0.025 Mt CO_2, which a priori is considered to be uneconomical.

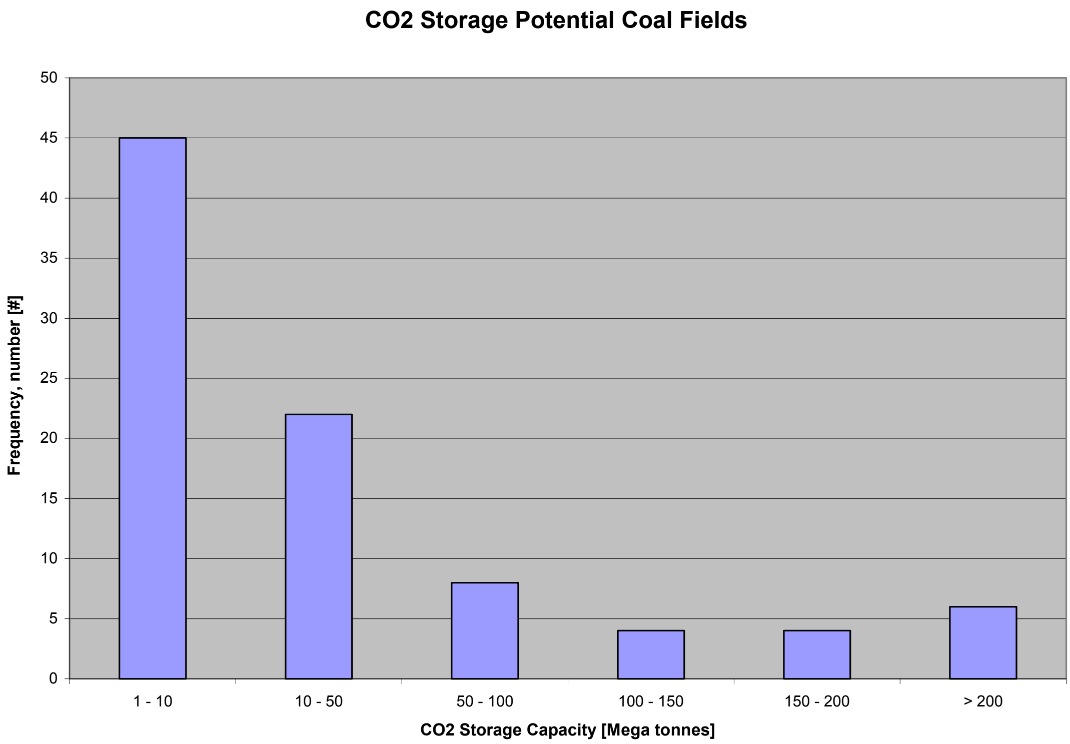

Figure 2.10 Number of deep unminable coal fields in OECD Europe per field-size class of CO_2 storage capacity.

Deep unminable coal fields with a capacity larger than 200 Mtonne of CO_2 are listed in Table 2.3.

Table 2.3 Deep unminable coal seams in OECD Europe with a CO_2 storage capacity of more than 200 Mtonne.

Deep unminable coal field	Country	Storage Capacity [Mtonne CO_2]	Remark
Eastern England	United Kingdom	1280	
Lorraine[7]	France	920	Estimated thickness
Chesire Basin	United Kingdom	640	
Oxford/Berkshire	United Kingdom	470	
Zeeland/N.Brabant	Netherlands	260	Uncertain depths
Saint Etienne	France	260	Estimated thickness

In Figure 2.11 the numbers of deep unminable coal fields are specified that either have estimates on both depth and thickness, estimates on depth only or no depth and thickness estimates of the coal layers. The total cumulative storage capacity for the deep unminable coal seams in Europe is 6 Gtonne CO_2.

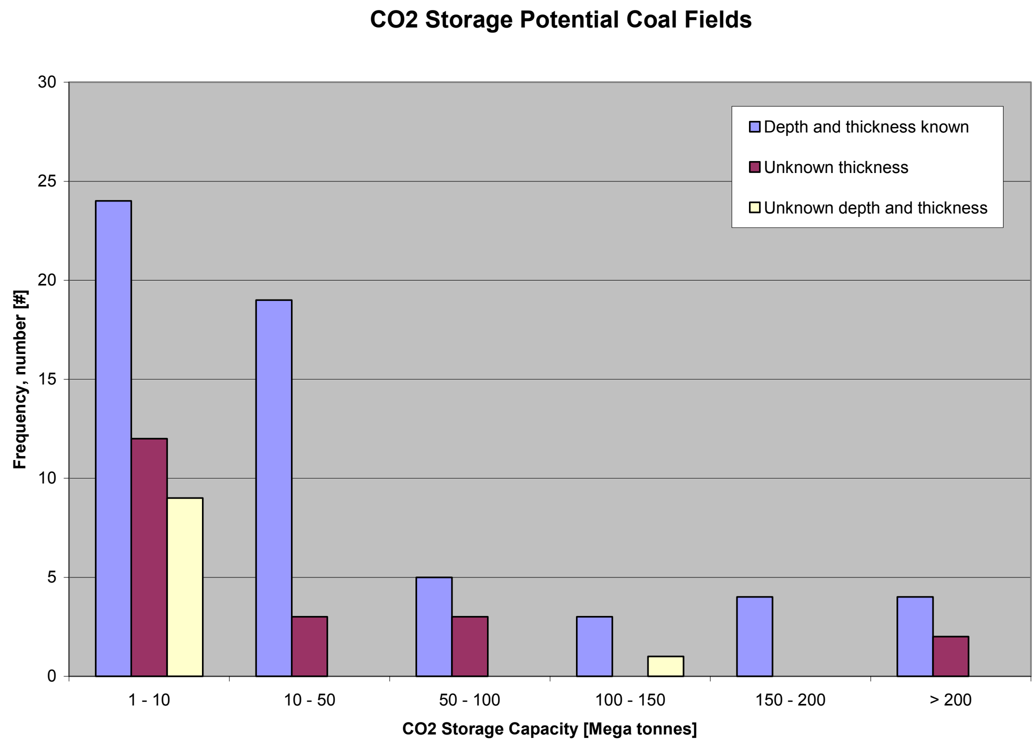

Figure 2.11 Storage capacity of deep unminable coal fields in Europe, per field-size class and categories of available information on depth and thickness.

[7] Here 'Lorraine' refers exclusively to the coal seams in the French part of the Saar/Lorraine basin.

3 CO_2 sources and their emissions

To construct elaborated cost curves for transport and storage of carbon dioxide in the European area, information on emission sources is indispensable. The minimum level of information required comprises information on type of the emission source (type of plant), location and annual emission of the plant.

3.1 CO_2 source database

The information on carbon dioxide sources, which was developed for the IEA Greenhouse Gas R&D Programme, was used in the present study (IEA GHG & Ecofys, 2002). For eight European countries[8] the data has been updated, completed and improved during the GESTCO project (Hendriks, 2003).

The database contains information on plant level regarding location, reported and estimated carbon dioxide emissions, quality of emission, type of fuel, fuel use etc. An extended description of the content and layout of the databases can be found in IEA GHG & Ecofys (2002) and in Hendriks (2003).

The database on sources for the European area contains 1917 different point sources of carbon dioxide. 1352 plants have annual emission of 100 kt or more (see Table 3.1). The remaining 565 point sources emit less than 100 kt/y and contribute for only 1% to the total emissions. Because of the limited importance in emissions, these plants are therefore not considered in the cost curve analysis of this study. The database contains information on power plants, ammonia plants, cement plants, iron and steel plants, hydrogen plants and refineries, gas processing plants, and ethylene plants, ethylene oxide plants and the category 'other'. The category 'other' contains information on e.g. aluminium plants, sugar processing plants, metal processing plants, and chemical plants. The total estimated emissions in the database sums to 1.5 Pg (1.5 Gtonne) of carbon dioxide. Figure 3.1 shows a carbon dioxide 'supply curve' for all identified industries. Fifty percent of all emissions originate from less than 10% of all plants. Twenty five percent of all emissions come from 2.5% of the plants. The share of the power production sector in the database amounts to about two-third of the total emission.

Table 3.2 provides an emission overview per sector for each country. Table 3.3 shows a breakdown of the emission to concentration of carbon dioxide in the flue gas of the plant for each sector. We estimate that about annually 22 Tg (Mt) of pure carbon dioxide is emitted, of which about 60% is coming from ammonia plants.

[8] Countries participating in the GESTCO project were: Belgium, Denmark, Germany, Greece, France, Netherlands, Norway, and United Kingdom. Other countries considered in this project are Sweden, Finland, Luxembourg, Italy, Spain, Portugal, Austria and Switzerland.

Table 3.1. Number of plants and size of carbon dioxide emission by sector.

	Plant emission larger than 100 kt/y		Plant emission larger than 1000 kt/y	
Sector	**Emission (Mt/y)**	**Number of plants**	**Emission (Mt/y)**	**Number of plants**
Ammonia	17	42	5	2
Cement	125	215	41	29
Ethylene	48	48	34	21
Ethylene oxide	0.4	3.0	0	0
Gas processing	3	6	1	1
Hydrogen	6	18	2	2
Iron & steel	153	62	146	31
Other	26	68	9	3
Power	1033	795	834	269
Refineries	123	95	94	50
Total	**1535**	**1352**	**1167**	**408**

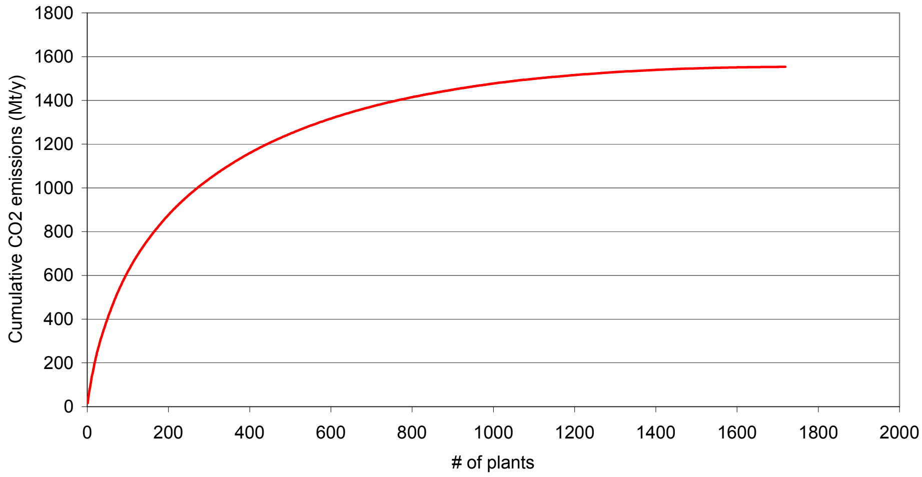

Figure 3.1. Cumulative emission of carbon dioxide from point sources in Europe.

3.2 Distribution of sources in Europe

Point sources of carbon dioxide are not equally spread over Europe. Table 3.3 shows the emissions for each country per sector. An analysis is made to the existence of clusters of CO_2 sources in Europe. Figure 3.2 is a possible graphical representation of the clustering. In the representation the amount of carbon dioxide is shown which is emitted from all sources in a certain area, which in this case is represented by a circle with a radius of 0.2 degree (approximately 20 km). The calculation is repeated over whole of Europe. The middle points of the circles are 0.025 degree (approximately 2 km) apart from each other. The figure shows that high concentration of CO_2 emissions can be found in the Ruhr area in Germany, in the Rijnmond in the Netherlands and in Central/Eastern part of the United Kingdom.

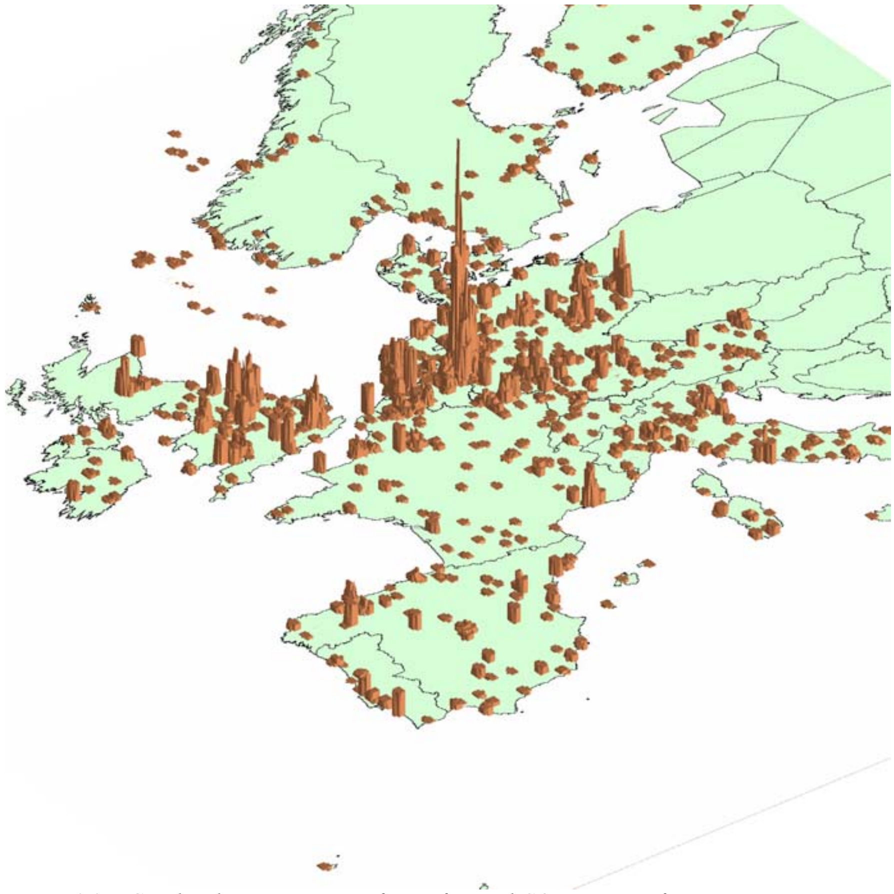

Figure 3.2. Graphical representation of size of annual CO_2 emissions from point sources in Europe.

Table 3.2 Emission of carbon dioxide (in ktonne CO_2) by sector and by country.

	Ammonia	Cement	Ethylene	Ethylene oxide	Gas processing	Hydrogen	Iron & steel	Other	Power	Refineries	Total
AUSTRIA	505	3,350	764	-	182	-	5,289	-	9,598	2,009	21,697
BELGIUM	1,553	4,741	4,912	249	-	115	12,284	-	21,632	6,782	52,266
DENMARK	-	1,388	-	-	-	-	106	-	30,307	1,300	33,101
FINLAND	-	720	718	-	-	54	-	-	20,874	1,927	24,292
FRANCE	2,159	16,139	5,399	70	-	108	16,020	16,460	74,360	18,321	149,035
GERMANY	4,102	32,326	11,525	296	1,266	3,743	67,375	82	361,687	18,868	501,270
GREECE	422	9,414	32	-	-	47	2,550	-	45,731	3,685	61,881
ICELAND	12	-	-	-	-	-	-	-	-	-	12
IRELAND	71	532	-	-	-	-	62	-	12,448	699	13,812
ITALY	-	15,808	4,669	22	-	674	14,577	-	94,248	18,231	148,230
LUXEMBOURG	-	735	-	-	-	-	268	-	1,189	-	2,192
MALTA	-	-	-	-	-	-	-	-	-	-	-
NETHERLANDS	6,777	664	8,086	150	-	1,412	6,592	-	50,993	11,461	86,136
NORWAY	814	1,425	1,014	-	-	-	3,638	4,305	16,257	2,028	29,479
PORTUGAL	223	4,103	700	-	-	-	588	-	20,275	2,931	28,820
SPAIN	150	18,679	3,025	44	-	293	2,307	-	75,825	9,397	109,720
SWEDEN	-	2,085	1,374	27	-	129	1,357	-	10,072	4,113	19,158
SWITZERLAND	47	2,720	77	-	-	-	-	-	1,634	1,272	5,750
UK	1,374	10,986	6,241	110	2,253	254	22,643	10,124	192,318	20,343	266,646
Total	18,208	125,815	48,536	968	3,700	6,829	155,657	30,971	1,039,448	123,367	1,553,499

Table 3.3 Division of emission by concentration of carbon dioxide in the flue gases of the plant.

Sector	CO_2 in flue gas (%)	Emission (kt/y)	Share in emission (%)
Power	3%	224	14%
All sectors	3%	224	14%
Ammonia	8%	5	0%
Other	8%	31	2%
Power	8%	134	9%
Refineries	8%	124	8%
All sectors	8%	294	19%
Hydrogen	11%	2	0%
All sectors	11%	2	0%
Ethylene	12%	49	3%
All sectors	12%	49	3%
Iron & steel	15%	156	10%
Power	15%	681	44%
All sectors	15%	836	54%
Cement	20%	126	8%
All sectors	20%	126	8%
Ammonia	100%	13	1%
Ethylene oxide	100%	1	0%
Gas processing	100%	4	0%
Hydrogen	100%	5	0%
All sectors	100%	22	1%
Total		**1553**	**100%**

4 Transport and storage equipment and cost factors

4.1 Transport

Carbon dioxide is transported by various means: by tanker, by pipeline, by tank lorry, in gas cylinders and as dry ice (solid carbon dioxide). However, transport of large amounts of carbon dioxide is done usually most conveniently by pipelines. In cases of large distances over sea, sometimes tanker transport might be more attractive. Tankers might be competitive at distances between 500 and 1000 km (Hendriks, 1992; Oremod, 2002; Kårstad, 2003). Tankers are more flexible in operation than pipelines, and expensive investment can be avoided when dealing with sources relatively short in operation.
Transport by tanker lorry is very costly and physically difficult. For the transport of 1 Tg[9] of carbon dioxide, the annual production of a 300 MWe natural gas-fired power plant, over 40,000 tanker lorry transports would be required.

Carbon dioxide is largely inert and easily handled. It is already transported in high-pressure pipelines. There are over 3000 km of carbon dioxide pipelines in the world, mainly in North America, which have been transporting CO_2 since the early 1980s. The transported CO_2 is originating from natural underground sources and mainly used for enhanced oil recovery projects.

Carbon dioxide should be transported at high densities for optimal use of pipeline capacities. A high density can be obtained by compressing the carbon dioxide. Compression requires investment and energy and should be limited to a minimum. More technical background information on transport can be found in Appendix I.

4.1.1 Pipeline design and construction

The conditions that should be considered in the pipeline design are internal and external pressure and temperature, fluid expansion effects, dynamic effects (e.g. impact, wind, earthquake, vibration, subsidence, and wave and currents), live and dead loads, thermal expansion and contraction, and relative movement of connected components. Design methods and practices used for natural pipelines generally apply for the design of carbon dioxide pipelines.

4.1.2 Booster stations

Booster pumps are required for longer pipelines or hilly terrain to compensate for pressure losses along the line. The stations will probably be centrifugal pumps driven by electrical motors or gas turbines. Each booster station could be equipped with intake and discharge pressure controls. Automatic shutdown devices can be provided for conditions such as low suction pressure, high discharge pressure, and high pump case, high pump case temperature, low flow, and seal failure. The central control centre will

[9] 1 Tg = 10^9 kg = 1 Mtonne

be equipped to start and stop the booster pumps, regulate flow into the pipelines and shut down the system in case of an accidental release of carbon dioxide.
Offshore, it is much more difficult and expensive to construct booster stations. For long distances, the optimal pressure and pipeline diameter will therefore be different from onshore applications.

4.1.3 Costs of pipeline transport

The costs of pipelines can be categorised in three items:

- Construction costs
  - Material/equipment costs (pipe, pipe coating, cathodic protection, telecommunication equipment; possible booster stations)
  - Installation costs (labour)
- Operation and maintenance costs
  - Monitoring costs
  - Maintenance costs
  - (Possible) energy costs
- Other costs (design, project management, regulatory filing fees, insurance costs, right-of-way costs, contingencies allowances)

The costs are influenced by a number of factors:

- length of pipeline
- diameter of pipeline (which is especially influencing material costs)
- required (internal and external) coating
- pipeline material specifications, depending on:
  - applied (max) transport pressure
  - impurities present in the carbon dioxide (e.g. SO_2, H_2S, N_2)
- possible need for booster stations (requires also power)
- terrain conditions (construction costs will increase for areas like mountains, natural parks, slumps, and populated area)
- number and size of crossings (waterways, roads, coastline)
- safety requirements (over-pressure or under-pressure protection valves)
  - in populated areas (increased number of valves; increased thickness of pipeline)
  - avoiding areas (populated, natural parks)
  - installing precaution measures (blowers for dispersion in case of blow out)
- possible requirement for carbon dioxide storage/buffer
- onshore and/or offshore construction
- presence of pipeline corridors
- cross border construction
- climatological circumstances
- country specific circumstances (e.g. differences in labour costs)

Figure 4.1 shows pipeline investment costs as function of the pipeline diameter. The figure has been composed based on information from various literature sources. The costs do not include possible needed booster stations. The figure shows clearly higher estimated costs for offshore lines relative to onshore lines. The costs may differ substantial from site to site. Especially terrain conditions influence the costs significantly. Construction of a high-pressure pipeline in the Rijnmond area with many

waterways, industry and a high population density costs many times more than a pipeline through agricultural area in Germany.
The investment costs for booster station (re-compression stations) are not very sensitive to flow size of the carbon dioxide transported [IEA GHG, 2002]. Onshore booster stations costs varies from 6 to 8 M€ over a wide range of capacity. Offshore booster stations are typically twice as expensive.
The operation and maintenance costs comprise maintenance of the pipeline and booster station (e.g. regular inspection of leaks – visual as well using 'pigs' and repairing) and operational costs (e.g. monitoring point along the pipeline, booster stations and block valves are tied back to a central operations centre). Although these costs may vary from pipeline to pipeline, a reasonable approximation of the annual O&M costs (excluding energy costs for recompression at the booster station) is 3% of investment for pipelines and 5% of the investment costs for booster stations.

Pipeline transport is a mature technology and applied at a wide scale throughout the world. It is not expected that costs of pipeline will drastically go down in the future. On the other hand, costs might go up through additional required safety regulations and increased complexity of pipeline corridors. In this study we assume therefore no cost changes in real cost terms for transportation in the next 20 to 30 years.

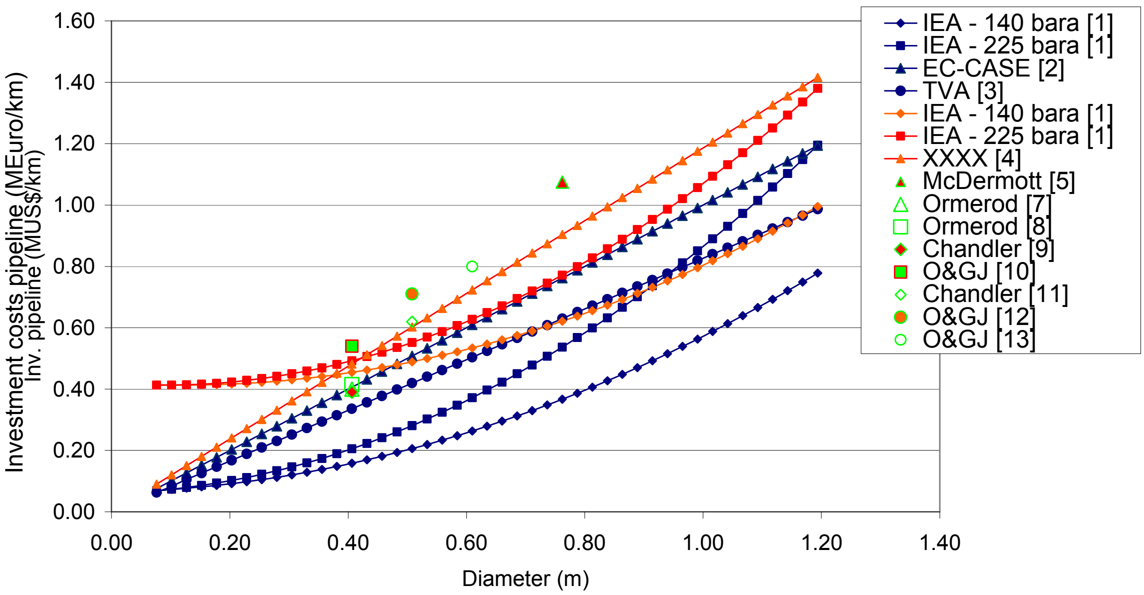

Figure 4.1. Pipeline investment costs (excluding possible booster stations) obtained from various literature sources. [1]: IEA, 2002. pipe line class ANSI 900# (for pressures up to 140 bara) and pipe line class ANSI 1500# (for pressures up to 225 bara) [2] Hendriks, 2003; [3] TVA, 2003; based US situation compiled using NG pipeline data reported in O&GJ. [4] based on confidential information; [5] Mc Dermott, 1999 and Mc Dermott, 2001; X-60 grade 30-inch pipe based on API-RP1111, CFR Part 192 and CFR 2883. [7] Ormerod, 1994 for rural area; [8] Ormerod, 1994 for urban area; [9, 11] Chandler, 2000, [10, 12, 13] O&GJ, 2000.

For illustration, Figure 4.2 shows the carbon dioxide transport costs (expressed in €/t) based on the reported investment costs of the studies referred to in Figure 4.1. The costs are including O&M costs. Assumed are operational lifetime of the system of 20 years and discount rate of 10%. The calculations have been performed following the guidelines on economic calculations given by IEA GHG R&D Programme. A full description of the cost calculation methodology will be given in chapter 5.

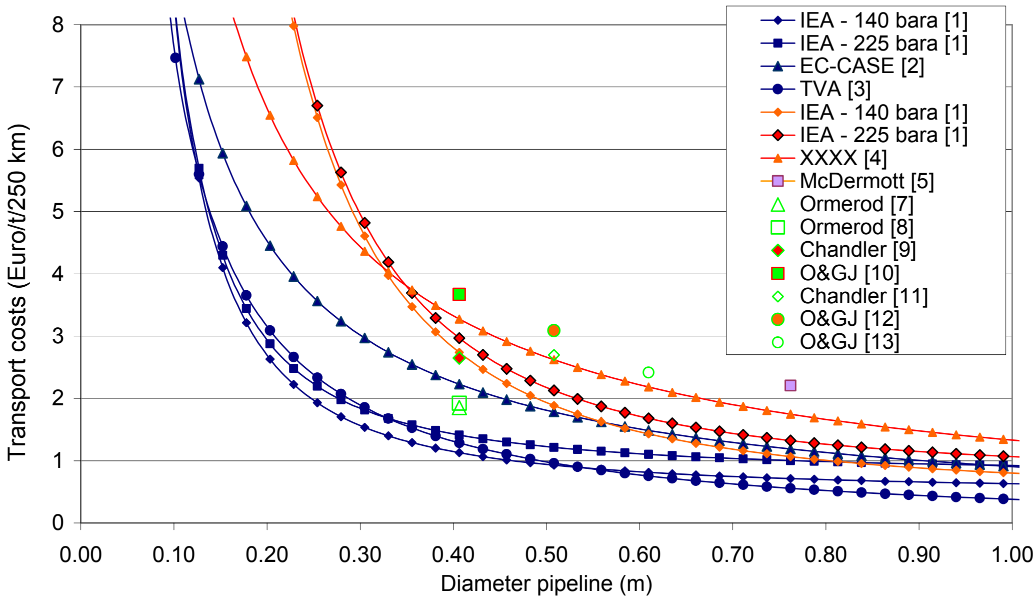

Figure 4.2. Carbon dioxide transport costs (euro/tCO₂) based on information in Figure 4.1. Assumed is 8000 hours of yearly operation, operational lifetime of 20 years, and discount rate of 10%.

4.2 Storage

The equipment for injection of CO_2 is relatively simple and comparable to high pressure gas production equipment. It contains a cased well with an injection tube into the deep saline aquifer or reservoir connected to the transport pipeline with an injection head. It is assumed that the transport pressure of 8 MPa is sufficient and no additional compression is needed. The wellhead is provided with SCADA[10] and remote control.

A division in 4 categories of capital investment costs (CAPEX) was made:

- Site development costs
- Drilling costs
- Surface facilities
- Monitoring costs

The final cost calculations (see chapter 5) also include the yearly returning costs (OPEX). These costs are taken as a certain percentage of the initial CAPEX costs and can vary slightly, depending on the chosen storage option. Most of the OPEX is related to the daily operational costs of a storage facility and the maintenance costs. The latter costs include maintenance of the platform and (possibly) well repair. A third category of OPEX constitutes costs of monitoring the storage facility for safety and effectivity.

[10] SCADA = System Control And Data Acquisition.

4.2.1 Site development costs

These costs are the “fixed” costs related to the site and the type of storage. This comprises of:

- Site investigation costs. This includes geological characterisation of the subsurface, based on (not always) available geological and geophysical data. In general it can be stated that for most gas and oil fields a wealth of information (drilling data, 2D and 3D seismic data, reservoir data) is available. Access to this data depends on the legal regulations.

- The preparation of the drilling site, including mobilisation and demobilisation of drilling equipment.

- Environmental impact assessment studies (if necessary), engineering design costs, licensing and land lease costs.

4.2.2 Drilling costs

The costs of drilling strongly depends on the depth and thickness of the reservoir, and, if necessary, horizontal drilling to enhance the injectivity of the storage medium. The costs also depend on the remoteness of the area, the country etc.

In literature a wide range of costs per meter are given, but it is not always exactly known which costs are included.

A few studies on the drilling costs in Western Europe are available. The present study is mainly based on recent studies by Wildenborg et al. (1999) and Van Bergen (2003).

Wildenborg et al (1999) mention the following drilling costs:

Onshore:	1350 €/m, depth< 3000 m
	2000 €/m, depth> 3000 m
Offshore:	2270 €/m, depth< 3000 m
	3500 €/m, depth> 3000 m

In this study the drilling costs include not only the actual drilling costs (rental of drilling equipment, daily rates, drilling bits etc.), but also the costs related to the casing, tubing, cementing, logging, testing, stimulation, well completion, injection-system, water treatment and subsurface completion.

A provision is made for deviation drilling, supervision, insurance and contingency cost (together up to 25% of the total drilling costs).

Van Bergen mentions drilling costs for ECBM. These costs are based on actual bidding data from drilling companies.

4.2.3 Surface facilities

These costs are related to the final preparation of the injection site. They are relatively low for onshore injection, in fact they include only the costs for preparing the site. However in the case of offshore injection they form a major part of the capital costs as they include platform costs. The re-use of platforms can reduce the costs considerably in the case of storage in depleted gas fields or oil fields, depending on the condition of a platform. However, often newly built platforms will have to be installed as well, because many existing platforms will reach their economic lifetime by the time depleted oil and gas fields will be used for storage. This information is not available for all the individual existing platforms. In our cost calculations, re-use is not included, resulting in a somewhat conservative cost estimate.

Two possibilities have been considered:

- Injection from a wellhead *platform*. Wildenborg et al. indicate costs of a wellhead platform of about 22.5 M€. Expert opinion gave values in the same order, indicating however higher costs at water depths of more than 100 m.

- Alternatives for a (unmanned) wellhead platform are *sub-sea* completion units, because in general no further processing of the injected CO_2 is necessary (suggesting that the last compressor stage is onshore). A Southern North Sea expert suggested about 10 M€. According to Kårstad (2002), control umbilical and sub-sea well frame in the remote Barentzsea (Snöhvit aquifer project) are estimated at 11 and 12 M€ respectively, whereas well completion is estimated at 9 M€. No data were available on the costs of multi-well sub-sea completion units.

Because drilling of deviated wells is common practice, it is assumed that the wells will be clustered to a few locations, reducing the number of sites. It is obvious that offshore the number of wells from one wellhead platform strongly influences the total costs. It is assumed that a pattern of wells is drilled, all connected to the injection facilities on one wellhead platform. In our calculations we (arbitrarily) assume a hexagonal 6 well pattern with a radius of 1 km.

Based on above-mentioned considerations, the costs of a wellhead platform have been taken as 25 M€ in shallow water and 50 M€ in deeper water (deeper than 100 m.).

4.2.4 Monitoring investments

Only a few data are known on the costs of monitoring,. A great deal of the monitoring is on a repetitive base, e.g. time lapse seismic survey every 3 or 4 years, geochemical sampling campaigns. But also continuous monitoring will be done, e.g. microseismic monitoring and pressure monitoring. The initial investments for these activities are shallow and/or slim holes for the emplacement of permanent monitoring equipment (seismometers, pressure and temperature meters, chemical registrations etc.) and the installation of downhole equipment in combination with fiberglas cables, which are used for a continuous monitoring programme.

For the cost calculations, all other monitoring costs are taken as operational expenses. Furthermore it is assumed, that the chosen monitoring strategy depends on the type of storage medium as well as on the onshore or offshore location of the storage site. Whereas onshore monitoring is important for both safety and effectivity (in reducing GHG emissions) of underground storage, it is assumed that offshore mainly storage effectivity is monitored. Post-operational monitoring is not included in the calculations.

5 Transport costs and storage cost curves

5.1 Transport costs

The cost of pipeline transport (expressed in euro per tonne transported) is computed in five steps.

- Determination of pipeline diameter
- Determination of pipeline investment costs
- Determination of power costs and booster station investment costs
- Determination of annual transport costs
- Computation of specific transport costs (i.e. costs in euro/t)

The calculated transport costs include possible booster station costs. These costs are added as per-km-costs. The installation of booster station is a trade-off between on the one hand the associated booster station costs and at the other hand larger pipeline diameter and wall thickness.

5.1.1 Method for transport cost calculation

Step 1: determination of the pipeline diameter

The pipeline diameter required is dependent on the (maximum) carbon dioxide flow and the applied velocity of carbon dioxide through the pipeline. The pipeline diameter is calculated by:

$$D = \frac{\left(\dfrac{F}{v \times \pi \times 0.25 \times \rho}\right)^{0.5}}{0.0254}$$

where:

D	=	pipeline diameter (inch)
F	=	flow (kg/s)
V	=	transport velocity (m/s) (=2.0 m/s)
ρ	=	density (kg/m^3) (=800 kg/m^3)
π	=	3.1415

Step 2: determination of pipeline investment costs

The pipeline investment costs are computed according to the equation given in IEA (2002), and which seems a reasonable approach for calculating investment costs.

$$InvPipe = \left(C_1 \times L + C_2 + (C_3 \times L - C_4) \times D + (C_5 \times L - C_6) \times D^2\right) \times 10^6 \times TF$$

where:

InvPipe	=	Investment pipeline (€)
L	=	distance (km)
D	=	diameter pipeline (inch)
TF	=	terrain factor[11]

For onshore pipelines: C_1 = 0.057; C_2 = 1.8663; C_3 = 0.00129; C_4 = 0; C_5 = 0.000486; C_6 = 0.000007
For offshore pipelines: C_1 = 0.4048; C_2 = 4.6936; C_3 = 0.00153; C_4 = 0.0113; C_5 = 0.000511; C_6 = 0.000204

The investment costs for booster stations, to recompress the carbon dioxide during long-distance transport, is largely independent from the carbon dioxide flow size. The costs for a booster station is therefore assumed constant and incorporated as costs per kilometre. Based on information in IEA GHG (2002), the booster station costs are assumed to be 7 M€ for onshore stations and 14 M€ for offshore stations.

$$InvBS = InvBS_{norm} \times L$$

where:

InvBS	=	investment costs booster station (€)
$InvBS_{norm}$	=	normalised investment booster station (€) (=7.10^6/200 = 35,000 €/km for onshore; 14.10^6/200 = 70,000 €/km for offshore)

Step 3 determination of the power use and costs for booster stations

Pumping energy for recompression of carbon dioxide in the booster stations is calculated according to:

$$P_p = \frac{\frac{1}{\rho} \times \frac{\Delta p}{\eta_p}}{Dist_{BS}}$$

where:

P_p	=	electricity use pump [J/kg/km]
ρ	=	density carbon dioxide (kg/m^3) (800 kg/m^3)
Δp	=	pressure difference [Pa] (4.10^6 Pa)
η_p	=	pumping efficiency (=75%)
$Dist_{BS}$	=	average distance between two booster stations (km) (=200 km)

Assuming an average pressure difference per booster station of Δp = 4 MPa, a carbon dioxide density of 800 kg/m^3, and a pumping efficiency of 75%, the energy consumption amounts to 6.7 kJ/kg (1.9 kWh/tCO_2) per 200 km.

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[11] Terrain factors according to IEA [2002] are: grassland 1.00; wooded 1.05; cultivated land, jungle, stony desert 1.10; <20% mountainous 1.30; > 50% mountainous 1.50. For this study, an average value for TF of 1.20 is taken.

Step 4 determination of the annual transport costs

The annual costs are an addition of the annualised investment costs, annual expenses and other running costs, i.e. costs for electricity use in the booster stations.
The investment costs comprise pipeline investment and investment for (possible) booster stations for recompressing the carbon dioxide.

$$AC_{I+O\&M} = -PMT(DC, LT, InvPipe + InvBS) + FOMPipe \times InvPipe + FOMBS \times InvBS$$

where:

AC	=	annual cost (€/y)
DC	=	discount rate (%/y) (=10%/y)
LT	=	operational lifetime (y) (=20 y)
FOMPipe	=	O&M factor pipeline (%) (=3%)
FOMBS	=	O&M factor booster station (%) (=5%)

Step 5: computation of the specific transport costs

In this last step the specific costs (expressed in €/tCO_2) is computed by dividing the annual costs by the yearly amount of carbon dioxide transported.

$$SC = \frac{AC}{F \times SperY \times LF} + CP \times P_p \times L$$

where:

SC	=	specific transport costs (€/kgCO_2)
SperY	=	seconds per year (s/y) (= 31536000 s/y)
LF	=	load factor (%) (=90%)
CP	=	Costs of power (€/kWh) (=0.04 €/kWh)

5.1.2 Resulting transport costs

Figure 5.1 and Figure 5.2 show the transport costs per tonne of carbon dioxide as function of the transport flow (t/s) for various distances. The costs calculations are based on the aforementioned equations.

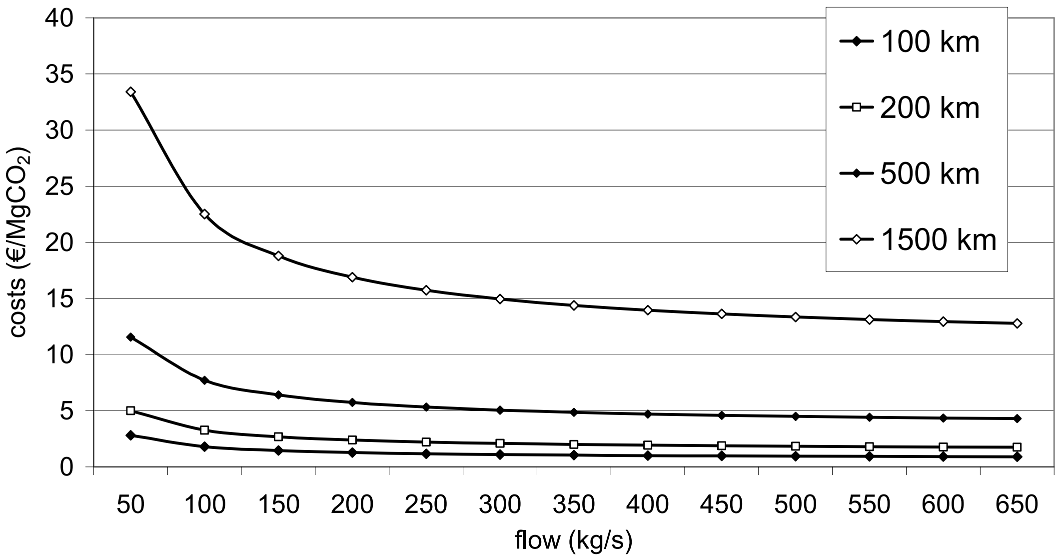


Figure 5.1 Pipeline costs including booster stations for transport of carbon dioxide

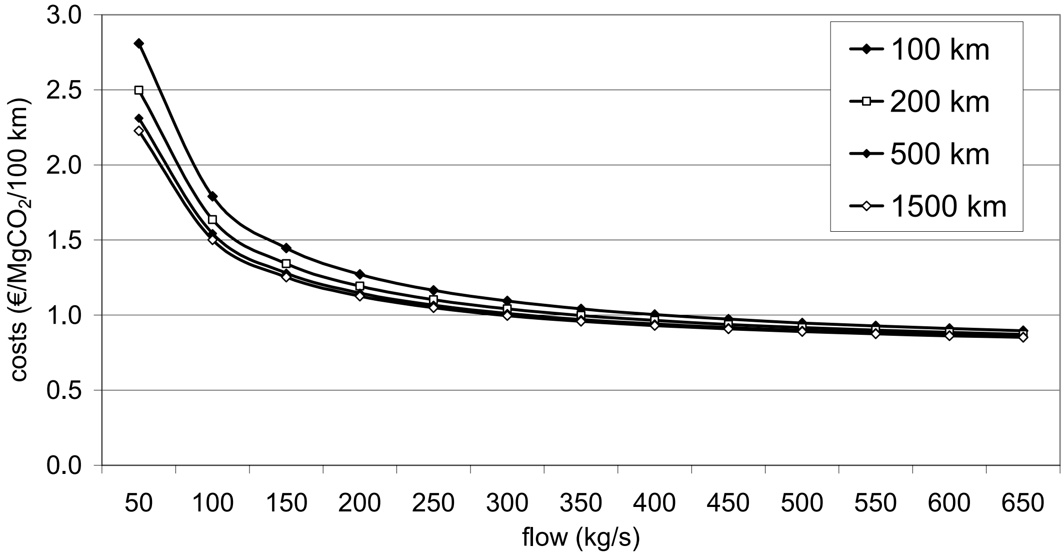


Figure 5.2. Pipeline costs per 100 km including booster stations for transport of carbon dioxide

5.2 Storage cost curves

5.2.1 Method for storage cost calculation

General assumptions

The background of the cost calculation curves is to get insight in the storage costs related to the total capacity. The presented cost calculations do represent a rough idea of the total costs to be made for the storage of injected CO_2. The costs of an individual storage facility will depend on the area, the type of reservoir and its local physical properties (flow rate), the amount of (exploration) work necessary to access the reservoir (e.g. depth and number of wells). As site-specific data are often not available, the present calculations therefore do not represent individual cases.

The following assumptions have been made for the calculations of the costs of CO_2 storage:

- The calculations are partly based on figures converted from former European currencies to euro. The baseline for the cost calculations is the year 2000. 1 US$ = 1 € is taken as the currency exchange rate.

- Each storage structure is filled within 20 years, the assumed lifetime of the storage facility and assuming that sufficient CO_2 is available.

- In order to use the full storage capacity within the lifetime, the number of wells necessary to achieve this was calculated, based on the possible storage per well per year. Because no data on the injectivity of the deep saline aquifers and reservoirs are known, this storage capacity per well was estimated, mainly based on data from literature (Smith et al., 2001) and the Sleipner field (Kårstad, 2002).

- Only a few (generally company confidential) data are available on the time at which a potential storage site will be available. This is important for producing oil and gas fields, because they are not immediately available for storage. Nevertheless, for the calculation of the storage costs it is assumed that they are available at this moment.

- The cost calculations are based on the levelised costs, assuming a discount factor of 10%.

- The data reported in the literature in general have a large spread. For example drilling costs can vary from € 300 up to € 3000 per meter. The combined effect of the variation in depth to the top of the reservoir, the drilling costs per meter and the O&M rate are analyzed by Monte Carlo simulation.

- CO_2 is delivered by pipeline at the storage facilities pressurized at 8 MPa. Pipeline costs and compression costs are not included in the storage costs. They have been taken into account in the transportation and storage costs (Chapter 6). No injection pumps are necessary. The pipeline is directly connected to the well head. Pressure monitoring and safety valves are part of the wellhead equipment.

Capital Investment costs (CAPEX)

The cost calculations are based on various classes of CAPEX costs as mentioned in Section 4.2. Tables F.1 to F.5 in Appendix F show the values that have been used in the calculations for each of the storage options. These tables include the following details:

1. Site Development Costs
   For all storage options estimates are made for the different fixed costs. A summed total has been used in the calculations.

2. Drilling Costs
   The drilling costs are based on a simple formula given by Wildenborg et al. (1999):

   Drilling Cost / m*(Depth + Reservoir Thickness) + 2*Drilling Cost / m*Horizontal Drilling Distance.

   Note:
   One of the most important factors concerning the storage costs is the injectivity of the reservoirs, deep saline aquifers and coal seams. Nowadays horizontal drilling is a well-developed standard technique, which can increase the injectivity of the formations. It is expected that horizontal drilling will be applied frequently. In the calculations it is assumed that horizontal drilling is always part of the drilling. This implies a “conservative” estimate of the drilling costs.

3. Surface facilities

   The third part of the CAPEX is important for offshore injection (mainly platform costs). Based on expert opinions, the costs of a (unmanned) wellhead platform in the Southern North Sea (water depth up to 50 m) is taken as 25 M€. For deeper water like in the northern North Sea the costs of a wellhead platform is higher, estimated at 50 M€. The costs of the platforms seem to be low, but they do have no extra facilities for compression, drying etc. An alternative to a platform is a sub-sea completion unit. The costs are estimated at 10 M€ in the southern North Sea up to 12 M€ for a single-well sub-sea completion unit in the Barents Sea.

4. Monitoring costs

   Only for monitoring of onshore storage additional investments for monitoring wells are included in the calculations. Monitoring flow rates, pressure etc. are assumed to be a part of the injection facilities themselves and therefore are a part of the well completion costs. Concerning offshore storage it is assumed that efficiency control is mainly done by time-lapse seismics. One reference (Benson & Myer, 2002) discussing monitoring techniques mentions € 0.03/tonne CO_2 for time-lapse seismic surveys.

In our calculations the costs of the time-lapse surveys and other monitoring techniques are included as operating and maintenance costs and are estimated at about 2% - 3% of the CAPEX, which is in agreement with the aforementioned reference.

Operational costs (OPEX)

The yearly expenses for the operation and maintenance of the storage facilities form the second category of costs. As a rule of thumb, operational costs as well as maintenance costs are generally taken as a certain percentage of the investment cost. Concerning the maintenance costs, this may vary between 2% and 4%. Regarding the operating costs, a difference has been made between onshore and offshore storage. In general, operational costs for offshore facilities are higher due to the remoteness of the storage facility compared to onshore storage.

A third category of returning costs is due to monitoring. The CAPEX compensates for these costs by adding a certain percentage to the CAPEX. We anticipate higher cost for onshore monitoring compared to offshore monitoring. As an example, time lapse seismic data acquisition offshore is less expensive than onshore data acquisition.

5.2.2 Resulting storage cost curves

Based on the aforementioned criteria and the generalized input data, the costs for every individual storage option have been calculated. These results have been used as input for the CO_2 transport-storage implementation schemes (Chapter 6).

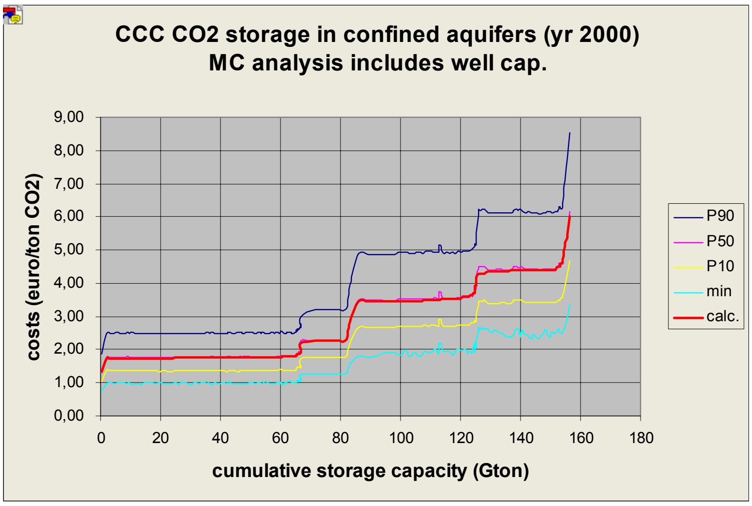
Two sets of cost curves are given, one set representing the virtual costs for the year *2000* situation, whereas the second set of cost curves represents the virtual costs for the year *2020* situation (and levelised for the year 2000). The difference between the two reference years is based on different investment costs. It is assumed that in 2020 the drilling costs will be lower than in 2000 due to the implementation of faster and smarter drilling technologies. A reduction in drilling investment costs of 30% is taken, whereas all other costs, mainly hardware and location costs are assumed to stay more or less the same.

Probably monitoring costs can be reduced as well, but the year 2000 calculations already took low monitoring costs into account. It is assumed that only at the early stages of CO_2 storage, monitoring will be done intensively, primarily to gain experience with the various storage concepts and get confidence in the methods (i.e. safety evaluation, storage efficiency and reservoir behaviour). With experience and confidence gained this will lead to less necessity for intensive monitoring in the future. At the present time the costs of monitoring of the CO_2 storage pilots and demonstration plants is mainly restricted to seismic methods, especially time-lapse seismic surveys to study the CO_2 storage efficiency. In the future (relatively cheap) microgravity methods may partly replace these large-scale survey methods. Because low monitoring costs were already assumed in the year 2000 calculations, the monitoring costs were kept the same. It is assumed that borehole devices to measure pressure, temperature, volumes, will always form a part of the well completion including future application of thin fibreglass wires for advanced subsurface monitoring. These extra costs are part of the yearly O&M costs.

Several input data are just fixed because the real values are not known. Most striking are the relatively unknown depths of oil and gas fields in the Netherlands and in Norway as derived from the GESTCO database. In the calculations a fixed depth is taken whereas in reality this will vary. Also the drilling costs may vary considerably as well as the operational, maintenance and monitoring costs. Monte Carlo simulation has been performed to analyse the influence of these uncertainties. Of course more uncertainties do exist, but they have not been taken into account. For example the discount rate is taken as a given fact following the IEA rate, whereas most of the equipment is part of the well costs. Although offshore the costs of a wellhead platform or subsea completion unit is an important factor, their uncertainty is not taken into account, due to a lack of data to get an idea about the spread.
An important uncertainty is the flow rate per well. The flow rates for the calculations were chosen, based on real data from literature and ongoing practice (Norway). The variation in flow rate shows strong fluctuations in the outcome, partly based on the fact that a small increase or decrease (in the continuous distribution) of the flow rate can result in strong fluctuating patterns due to “discrete” (an extra well or even an extra platform) changes in the costs.

Cost curve for storage in deep saline aquifers

Figure 5.3 shows the cost curve for the combined onshore and offshore storage of CO_2 in deep saline aquifers. The costs start at a relatively low level, varying from as low as only € 0.60, up to € 5-6 /tonne CO_2. However, for 50% of the total storage capacity the costs lie between 1 and 2.50 euro per tonne. Comparing the year 2000 data with the year 2020 data the cost reduction is less than 20%.



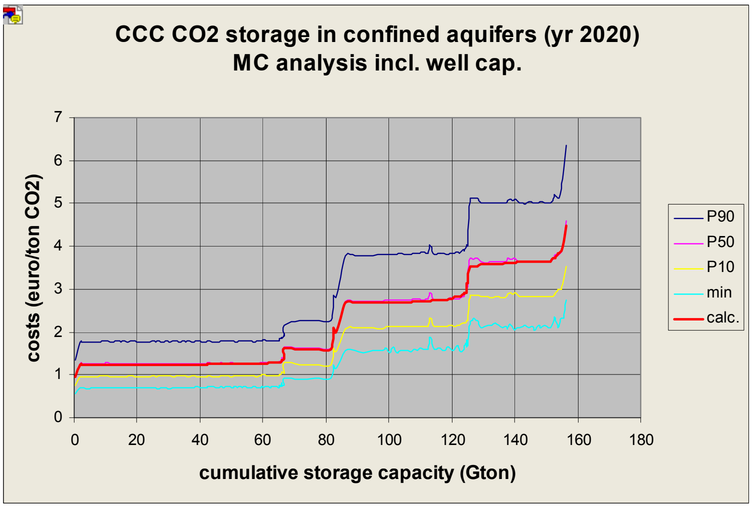
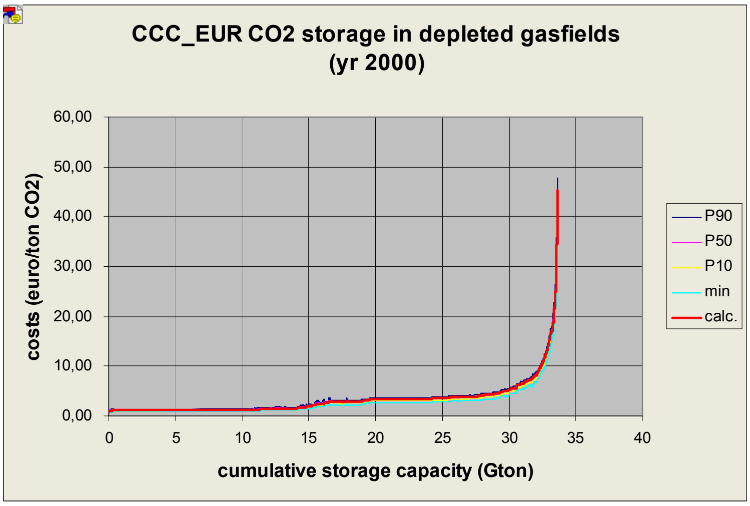


Figure 5.3 Cumulative cost curve of storage in confined deep saline aquifers, onshore and offshore combined The red curve shows the calculated costs. The other curves represent the results of the Monte Carlo analysis.

Cost curve for CO_2 storage in gas fields

Figure 5.4 shows the cost curve for the combined onshore and offshore storage of CO_2 in depleted gas fields. As can be seen the calculated costs are relatively low, varying from as low as only € 0.75 up to € 5 /tonne CO_2. The costs increase sharply when about 90% of all possible storage options have been filled, and are similar to the storage costs in deep saline aquifers. Up to 90% of the storage capacity shows costs of less than € 2 /tonne. Here too, there is only a slight reduction in costs for the year 2020, compared with the year 2000. The figure also displays the results of the Monte Carlo simulation, however the influence of the well capacity was not included. As shown, there is not much difference between the calculated (red curve) and the simulation results.



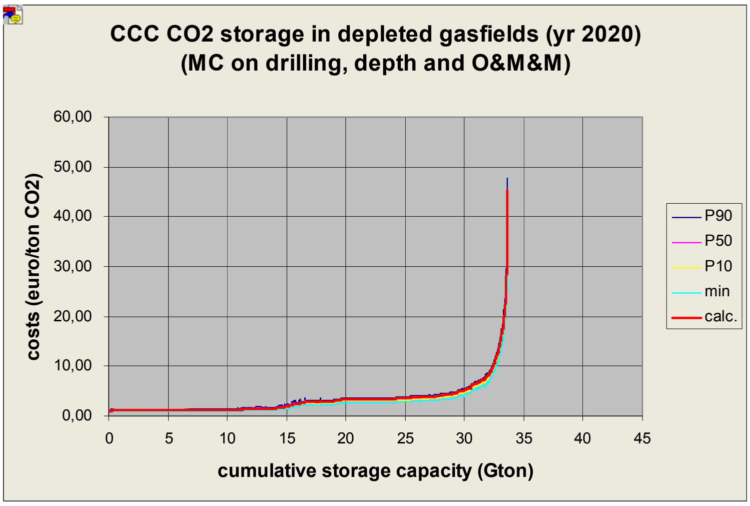
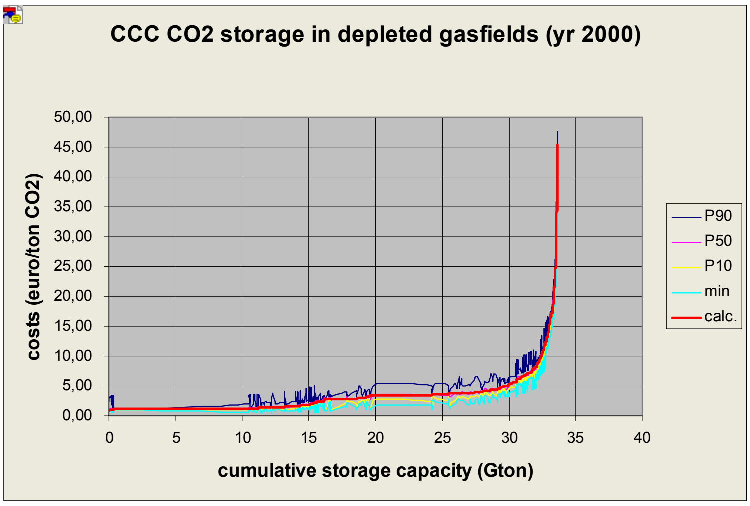


Figure 5.4 Cumulative Cost Curve of storage costs in depleted gas fields, onshore and offshore combined.

Figure 5.5 shows the Monte Carlo simulation results including the uncertainties in the well capacity. As can be seen, the uncertainties results in a spiky character of the cost curve. This can be attributed to the fact that changing the well capacity will result in more or less location/platforms and wells, which are discrete events.



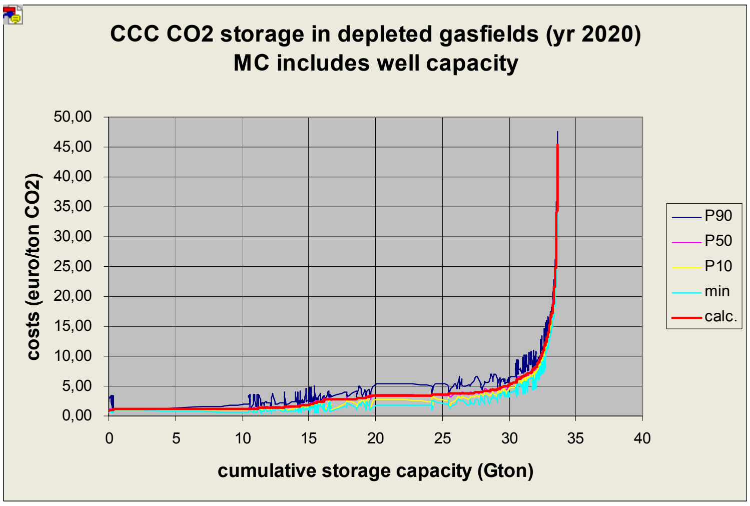
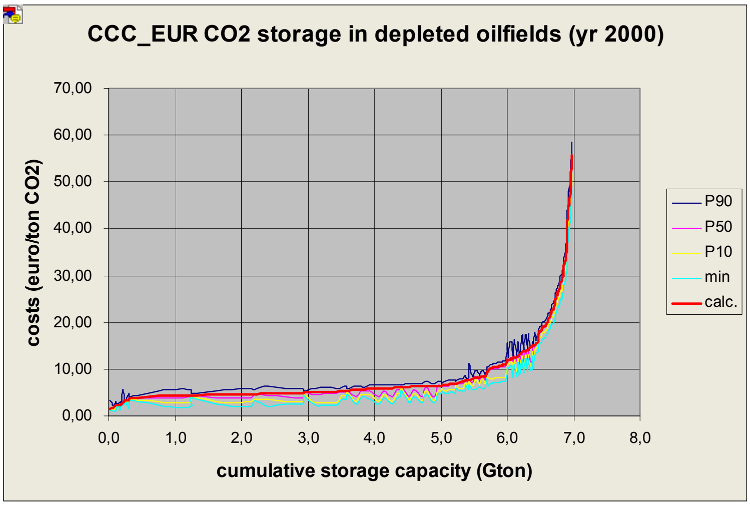


Figure 5.5 Monte Carlo results of storage costs in depleted gas fields. Changes in the well capacity are reflected in the "spiky" character of the cost curve and can in individual cases enhance or reduce the costs significantly.

Cost curve for CO_2 storage in oil fields

Figure 5.6 shows the calculated cost curve for the combined offshore and onshore storage of CO_2 in depleted oil fields. As can be seen the costs are relatively low, varying from only € 1.50, up to € 7.5/tonne CO_2. The costs increase sharply when about 80% of all possible storage options have been filled. Again the calculated costs for the year 2020 are slightly lower than for the year 2000, showing in general a cost reduction of less than 20%.



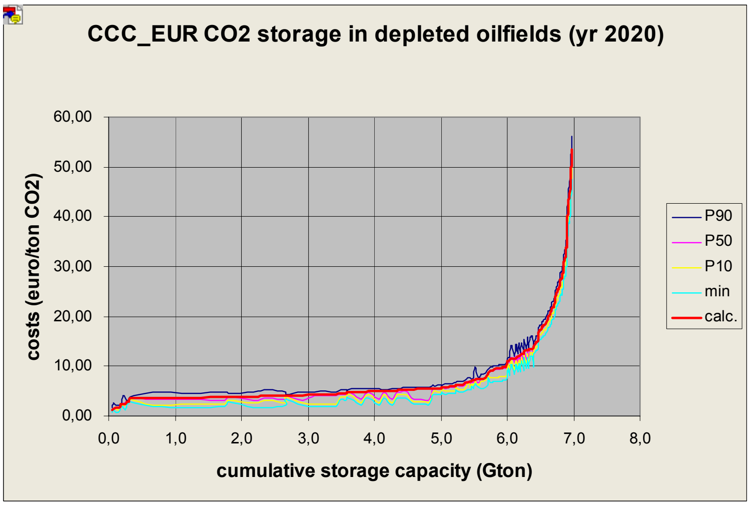
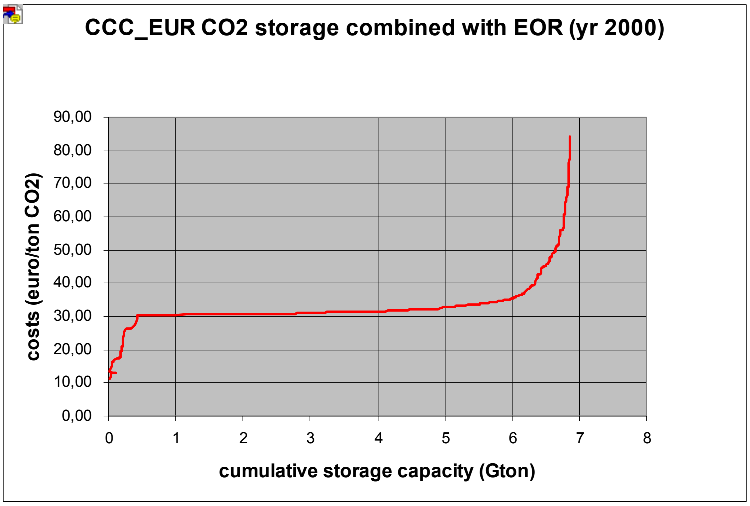


Figure 5.6 Cumulative cost curve of storage costs in depleted oil fields, onshore and offshore combined.

Figure 5.6 also shows results of the Monte Carlo simulation. As can be seen, the influence of the uncertainties in the input parameters is again limited.

Storage cost curve for incremental oil production

Figure 5.7 shows the cost curve for CO_2 storage in oil fields with incremental oil production. As can be seen the calculated costs are relatively high compared to storage in oil and gas fields. However, the incremental production of oil will result in extra revenues. The present cost curve shows costs, varying from € 6 up to € 40/tonne CO_2. The costs increase sharply up to 80 euro when about 80% of all possible storage options have been filled.



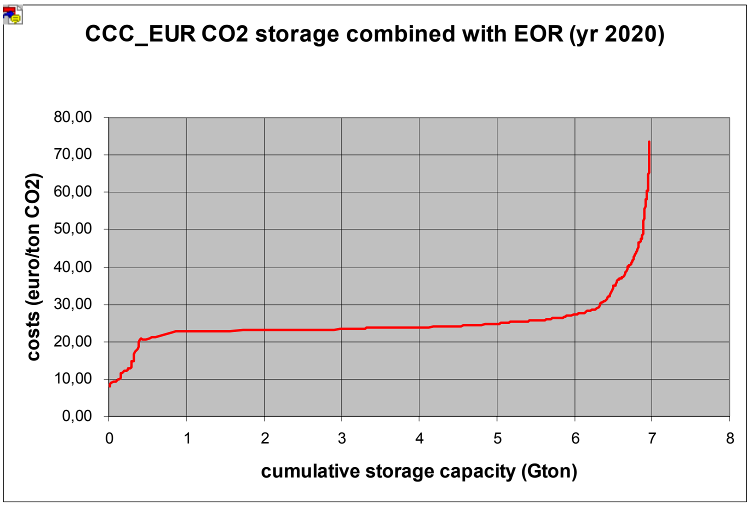


Figure 5.7 Cumulative Cost Curve of storage costs with incremental oil production, onshore and offshore combined.

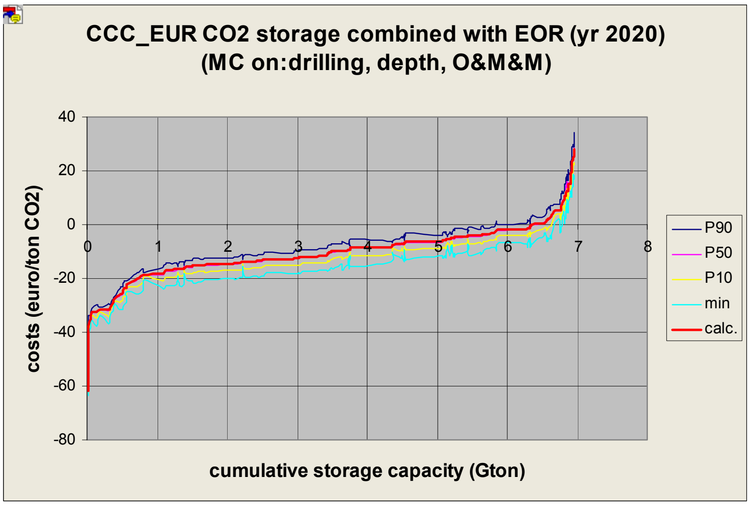
If we take into account the revenues due to extra oil production, EOR turns into a profit generating storage option as shown in Figure 5.8. The gross revenues (defined as the net revenues before taxes) are set at € 20 per barrel of extra oil produced[12]. It should be realized that there is quite a lot of uncertainty on the (future) oil price, which will have a large effect on the final outcome. Also the Unit Operating Costs are uncertain and heavily depends on the geographical and petroleum geological setting of the oil field. Extra production costs that are dependent on the specific setting of the oil field will lower the oil production revenues.

The calculated year 2020 cost figure show a relatively strong reduction in costs and increase in revenues. Although the cost range for the year 2020 is more or less the same, the costs and revenues for the individual fields differ strongly, and profitability in the year 2020 figures has a much longer range, up to 60% of the total storage capacity,

[12] The assumed gross revenue of € 20 per barrel of oil is based on an arbitrarily fixed oil price of € 25 per barrel of oil, whereas the Unit Operating Costs are estimated at € 5 per barrel of oil, which represents the North Sea situation at large.

compared to only 20% for the year 2000 cost curves. Because drilling costs form a large part of the total costs, EOR will benefit from reduction of drilling costs.

Figure 5.8 shows the Monte Carlo simulation results of the combined onshore and offshore storage option. The costs include the gross revenues of the incremental oil production. As can be seen, the influence of the uncertainties in the input parameters is much larger than for the storage in depleted oil and gas fields. The bandwidth is approximately about € 12 per tonne, probably reflecting the high uncertainties in drilling costs.



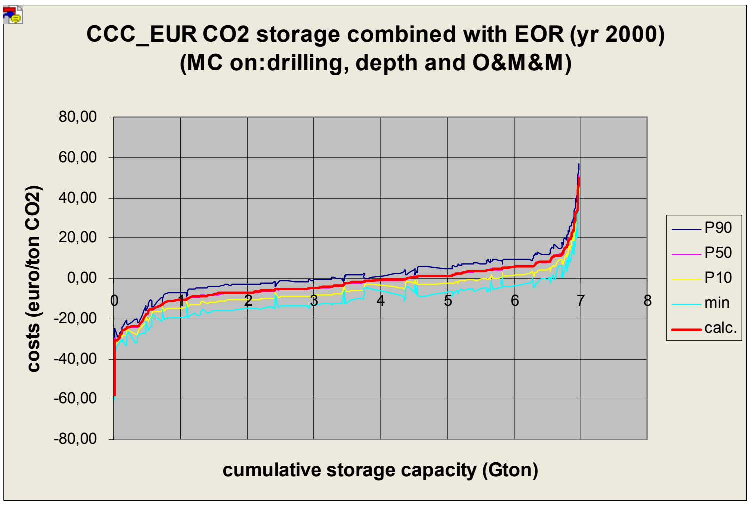
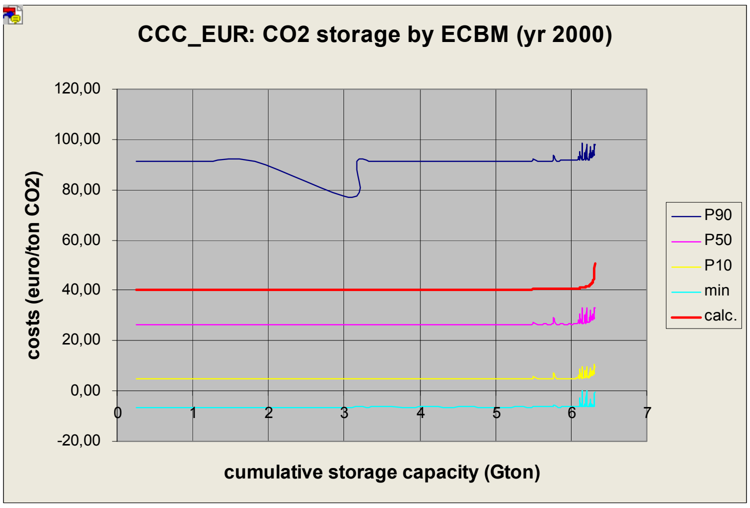


Figure 5.8 Cumulative cost curve of storage costs with incremental oil production, onshore and offshore combined. The cost figures presented include assumed gross revenues of € 20 per barrel of oil. Note that this number is highly uncertain and heavily depends on the geographical and petroleum geological setting of the oil field as well as on the changes in the future oil prices.

Cost curve for storage in coal beds with methane production

Figure 5.9 shows the calculated cost curve for the storage of CO_2 in coal beds combined with methane production. As can be seen the costs are relatively high, up to 40 €/tonne CO_2. The cost curves include revenues for gas production of 0.10 €/m^3 gas, which is equivalent to about 3.50 € /GJ.

The curve is rather flat because in the database most of the coal fields have the same characteristics and therefore the database does not discriminate on the costs. The year 2020 cost curves show considerable lower costs, because many wells have to be drilled for CO_2 storage in combination with ECBM and will therefore benefit from drilling costs reductions.



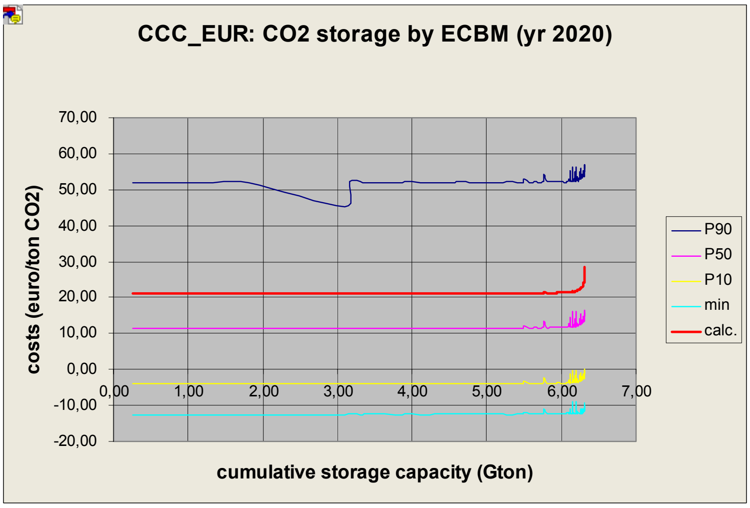


Figure 5.9 Cumulative cost curve of storage in coal beds combined with methane production.

Monte Carlo simulations show that the uncertainties in the input parameters do result in quite a large variation in the outcome. The bandwidth is relatively high compared to the other storage options and reflect the strong influence of the uncertainty in the depths of the coal fields combined with the drilling costs. The 2020 figures show costs reductions of 40 to 50%, due to the assumed lower drilling costs.

6 Integrated transport-storage cost curves

Currently, carbon dioxide capture and storage is hardly applied in Europe. Statoil, storing annually 1 Mt of carbon dioxide, carries out the only large-scale activity at present. The design of future implementation schemes of carbon dioxide capture and storage can still be made from scratch. The (political) perception of climate change and the role of carbon dioxide capture and storage in the abatement of the issue will determine largely which implementation scheme is most effective and efficient. Without firm political commitment large upfront investment for, e.g. pipeline infrastructure will not be made.

Implementation of carbon dioxide capture and storage (CCS) can be seen from the point of view that CCS will be an important technology for at least the coming half century. In that case a central pipeline grid connecting sources of CO_2 with storage location might well be an efficient and cost-effective system. This could be realised, for instance, by a central backbone system with satellite connections to individual sources and storage sites. A possible advantage of such a backbone system might be that remote large storage sites which would be prohibitively expensive for single sources to reach become an economically attractive storage option.

An alternative strategy is implementation on project basis, which can be realised by connecting one source to one storage structure (or to various storage structures nearby located to each other if one storage structure does not offer sufficient storage capacity).

The transport costs of carbon dioxide (expressed in €/tCO_2) are strongly influenced by the planning of the infrastructure, its design and the eventual utilisation of the pipelines. When less certainty exists about the role of CCS in the future the more likely it is that the technology is introduced on project base, i.e. one-to-one source-storage site connections without a central trunk line at least in the initial phase of CCS.

A parallel can be drawn with the introduction of natural gas schemes. In the Netherlands for instance, after the discovery of the huge natural gas reserves, in a relatively short time a natural gas infrastructure was completed. In an early stage large transport pipelines were projected and constructed from the North of the country to the southeast and southwest of the country. The already existing distribution networks for town gas were gradually integrated in the larger countrywide network. Except for the integration of the town gas distribution nets, this approach is an example of fast and large-scale introduction of the backbone approach. The economical risks were moderate as the government expected large revenues from natural gas sales.

On a European scale one can speak of an intermediate approach. After the construction of natural gas grid in many European countries, large transport pipelines were constructed, even up to the East in Russia. These large pipelines could economically be constructed because sufficient sales could be expected. Analogues like the natural gas grid can also be found in the electricity market. Liberalisation in the market causes expansion of many high capacity power lines that are constructed between countries.

The implementation of one or the other system will lead to different kind of planning, operating and financing schemes. Planning a large-scale infrastructure with large backbone trunk pipelines offshore and onshore and satellite connections will require high initial investment costs but may eventually lead to lower costs than a gradual evolution of individual projects growing to a larger system. Nevertheless, the risk of high up-front investments are high because of the risk of a sudden collapse of the market, i.e. the price of CO_2 becomes very low[13]. This might be caused e.g. by the changing perception of climate change (climate change is not regarded an issue anymore), more cost-effective ways have been found to counter-act emissions of CO_2 or unacceptable environmental problems arise with this technology.

In this project we develop two approaches. In the first approach, we assume that all individual sources will be connected to a reservoir that is sufficiently large to store its total emission of carbon dioxide for 20 years. In addition it is assumed that the connection will be the cheapest option available, i.e. the combined costs for transport and storage for that specific source is the cheapest possible.

In the second approach, we assume the construction of a large backbone pipeline. The total costs of the backbone and the costs of the satellite pipelines to the reservoirs determine the costs for backbone transport. These costs are translated to fee costs per tonne of carbon dioxide delivered to the backbone pipeline. The costs for the satellite pipeline from the source to the backbone are added to the fee costs. Sources, which can be connected more economically individually to reservoirs, i.e. not using the transport capacity of the backbone, are allowed to do so.

The cost curves are developed for two different sets of starting conditions. In the set of cost curves calculated for the first set of starting conditions, which is indicated by the term "**2000-scheme**", the current situation is the starting point, i.e. current state-of-the-art technology for drilling and cost figures as known today, and storage in hydrocarbon fields, which are available or will become available before 2020. In the calculations done with the second set of starting conditions, which is referred to with the term "**2020"-scheme**, the anticipated technology and cost figures as may be available in 2020 are taken. Due to development in knowledge and technology drilling costs will have decreased (for details see Section 5.2). Transport costs remains constant (see Section 4.1.3). In this scheme, it is assumed that all hydrocarbon fields are available. It should be stressed that the cost curves do not represent a projection of future transport and storage activities but rather a graphical representation of the transport and storage opportunities ordered from the lowest costs to the highest costs under (cost) conditions that either represent present or future conditions.

The following sections give a description of the method for constructing implementation schemes and the resulting transport-storage cost curves. The calculation method of transport and storage costs has been explained in the preceding Chapters 4 and 5. The authors would like to repeat here that in this study *only transport and storage costs* of carbon dioxide are considered, i.e. capture and compression costs are <u>not</u> included.

[13] The carbon dioxide price is determined by (possible) values in e.g. the emission trading scheme (ETS), carbon taxes and green certificates market.

6.1 Method for constructing implementation schemes

For the cost curve construction we followed two approaches, which have been introduced in the previous sections. In the first approach it is assumed that all sources are connected individually with a storage reservoir. In the second approach, a backbone pipeline is assumed.

6.1.1 Source to storage structure (1:1) approach

In the first step, considering all possible source-storage structure combinations, the source-storage structure combination with the lowest specific costs is determined (i.e. the sum of the transport costs and storage costs, expressed in euro per tonne of carbon dioxide stored). Only storage structures with sufficient storage capacity are taken into account, i.e. only those storage structures with a storage capacity equal or larger than the product of the annual emission of the source and the lifetime of the project. The costs are determined by calculating for all possible combinations the distance between the source and storage structure[14]. The transport costs are calculated following the method described in Sections 4.1.3 and 5.1. The transport costs are a function of the transport distance and the flow. Once the combination with the lowest cost has been found, the source is removed from the possible source list and the capacity of the storage structure is lowered with the required amount for the source.

This calculation procedure is repeated until one of the following three **criteria** were met:

1. there is no storage structure capacity left;
2. all CO_2 sources have been matched with a storage reservoir;
3. one of the cut-off criteria for costs are met; these criteria can be set in the beginning of the calculation procedure (e.g. a cut-off criterion is maximum specific costs).

In this way the cost curves are generated using all sources and storage structures. It is also possible to make a pre-selection for the type of sources and/or storage reservoirs. For instance the calculations are done for sources emitting pure carbon dioxide and for hydrocarbon reservoirs only. Table 6.1 gives an overview of the categories that can be made.

[14] The calculated pipeline length between source and sink is the shortest distance between the source and the sink multiplied by 1.15 allowing for extra kilometres when construction of a straight pipeline is not possible.

Table 6.1 Distinguished subclasses for large point sources of carbon dioxide emissions

Type of source
Ammonia (pure exhaust)
Ammonia (diluted exhaust)
Cement
Ethylene
Ethylene oxide
Gas processing
Hydrogen
Iron & steel
Other (e.g. aluminium, chemical)
Power
Refineries

Table 6.2 Distinguished subclasses for storage reservoirs

Type of storage structure
Onshore deep saline aquifers (confined, solution, unconfined)
Onshore oil fields (either with or without enhanced oil recovery)
Onshore natural gas fields
Deep unminable coal seams (ECBM)
Offshore deep saline aquifers (confined, solution unconfined)
Offshore oil fields (either with or without enhanced oil recovery)
Offshore natural gas fields

6.1.2 Backbone approach

The trajectory of the backbone is manually outlined at the hand of information obtained by the position and emission size of the sources and storage structures and information acquired through the source-storage structure (1:1)-approach. Preliminary analysis showed that a backbone pipeline most efficiently could be established connecting large concentrations of points sources on the European continent and United Kingdom. Extension further eastwards did not show significant economical advantage. The direction of the flow in the backbone is determined by supply and demand and could be in either direction.

In the backbone approach principally the same methodology is followed as in the 1:1-approach, with the inclusion of a backbone that is considered as an additional storage structure in the computational work. It is assumed that sources that deliver carbon dioxide to the backbone pay a uniform fee to cover the costs for the backbone and the costs for constructing the satellite pipelines connecting the backbone with the storage structures. The total transport costs for one source comprise therefore the transport costs from the source to the backbone and the backbone fee. The fee for the backbone has been derived through an iterative calculation process. In the first loop, the fee of the backbone is put very low. The result of the first loop is that a relatively large amount of carbon dioxide is delivered to the backbone. Subsequently, the required storage structures are selected with sufficient capacity to be connected to the backbone (selection based on lowest costs). The fee of the backbone is determined by dividing the total costs of the backbone and satellite backbone-storage structure connections by the amount of carbon dioxide transported through the backbone. The size of the backbone is calculated by taking a certain percentage of the total amount delivered to the backbone. The calculation process is repeated with the newly calculated backbone fee. As the fee is now reflecting a higher and more realistic value, a number of sources will prefer to store their captured carbon dioxide in a nearby reservoir when this will be a cheaper option than delivering it to the backbone. This will again result in a new backbone fee. This calculation process is repeated until the fee remains stable.

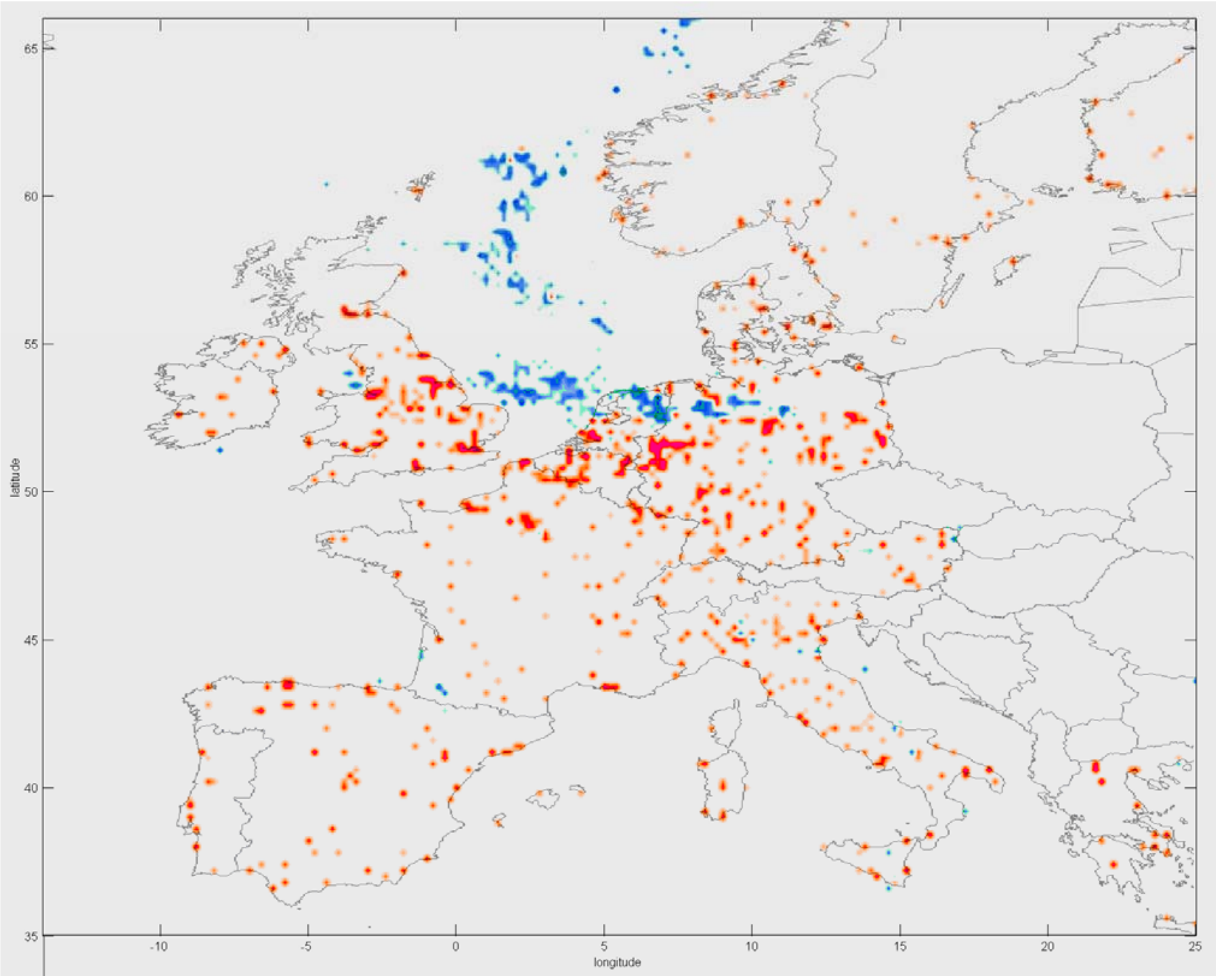


Figure 6.1 Graphical representation of source emission concentration (red dots) and capacity of storage structures (blue dots). Overlapping capacity of sources and storage structures are subtracted from each other.

6.2 Determination of the backbone route

An automated approach for the construction of the backbone would be extremely complicated. It is therefore done, based on information on location and sizes of the sources and storage structures and based on information obtained from the 1:1-approach. A useful map is the one that shows the concentration of carbon dioxide (e.g. the amount of carbon dioxide emitted per square kilometre). Such a map is depicted in Figure 6.1. Additionally this can be shown for the storage potential. A third map shows the result when both maps of the sources and storage structures are combined and the emissions in the same area are subtracted from the storage capacity (Figure 6.1). This map indicates the transport requirement of the carbon dioxide throughout Europe.

6.3 Resulting transport-storage cost curves

In total 32 runs have been made to design the cost curves for transport and storage of carbon dioxide in Europe. We considered only sources with an annual emission of at least 100 kt CO_2. In total 1352 sources with a summed annual emission of 1535 Mt have been selected. The operational lifetime of each transport and storage project is put to 20 years. The total amount to store over this period amounts to 30.7 Gt. The calculations are performed for two timescales with different costs and different availability of storage reservoirs. In the first timescale, i.e. the 2000-scheme, the reservoirs mentioned in Table 6.3 are most likely not available for storage of carbon dioxide and therefore are not taken into account. These reservoirs concern mostly the largest fields and comprise about 40% of the total storage capacity in hydrocarbon fields. Additionally, plots have been generated showing the cumulative length of pipelines in relation to the amount of carbon dioxide to transport and store. It should be noted that the length of all pipelines, regardless of size, have been summed up. The calculations have also been performed for the 2020-scheme, in which it is assumed that the storage starts from 2020.
The cut-off criterion for the storage costs has been set at 20 euro per tonne of carbon dioxide transported and stored. Preliminary analysis showed that higher allowed costs in the model would induce very long and relatively small pipelines which were considered by the authors as not realistic.

Concerning the storage reservoirs (storage structures), the following subclasses of storage implementation schemes have been created. For all these combinations, the calculations were done for the case without and the case with the construction of a backbone. A summary of the results is presented in Table 6.4 (2000-schemes) and Table 6.5 (2020-schemes).

A. All types of storage structures, i.e. confined deep saline aquifers, oil fields *without* incremental oil production, gas fields and deep unminable coal seams – offshore and onshore (see Run 1, Run 1bb, Run 1 2020, and Run 1bb 2020 in Appendix G.1)

B. All types of storage structures, i.e. confined deep saline aquifers, *without* incremental oil production, gas fields and deep unminable coal seams – *offshore only* (see Run 2, Run 2bb, Run 2-2020, and Run 2bb-2020 in Appendix G.2)

C. All types of storage structures, i.e. confined deep saline aquifers, oil fields *with* incremental oil production, gas fields and deep unminable coal seams – offshore and onshore (see Run 3, Run 3bb, Run 3-2020, and Run 3bb-2020 in Appendix G.3)

D. All types of storage structures, i.e. confined deep saline aquifers, oil fields *with* incremental oil production, gas fields and deep unminable coal seams – *offshore only* (see Run 4, Run 4bb, Run 4-2020, and Run 4bb-2020 in Appendix G.4)

E. Hydrocarbon fields, i.e. oil fields *without* incremental oil production and gas fields – offshore and onshore (see Run 5, Run 5bb, Run 5-2020, and Run 5bb 2020 in Appendix G.5)

F. Hydrocarbon fields, i.e. oil fields *without* incremental oil production and gas fields – *offshore only* (see Run 6, Run 6bb, Run 6-2020, and Run 6bb-2020 in Appendix G.6)

G. Hydrocarbon fields, i.e. oil fields *with* incremental oil production and gas fields – offshore and onshore (see Run 7, Run 7bb, Run 7-2020, and Run 7bb 2020 in Appendix G.7)

H. Hydrocarbon fields, i.e. oil fields *with* incremental oil production and gas fields – offshore only (see Run 8, Run 8bb, Run 8-2020, and Run 8bb-2020 in Appendix G.8)

6.3.1 Discussion of cost curves for subclass A

In this section the cost curve and the results of the calculations for subclass A are discussed. Results for the other subclasses can be found in Appendix G.

In subclass A, it has been assumed that all types of storage structures are available for storage, i.e. both onshore or offshore reservoirs can be used for injection and all hydrocarbon structures (oil fields, gas fields and coal seams). For the 2000-scheme, only the fields available now or which become available in the next twenty years are taken into account. This means generally that some of the largest fields are not yet available (see Table 6.3). In this subclass it is assumed that no incremental oil is produced. In the results for subclass A, there is no construction of a backbone pipeline. All point sources are connected individually with storage reservoirs. It is, however, possible that one sufficient large storage reservoir is connected with more than one point source.

Figure 6.2 gives a schematic representation of the pipelines, point sources (different symbol per type of source) and storage reservoirs (different symbol per type of storage reservoir). For the sake of completeness the figures related to subclass A have also been included in Appendix G.
In total 1352 point sources are considered with a total emission of 30.7 Gt. 1063 point sources with an emission of 29.3 Gt have been connected to a storage reservoir. Because of the large availability of storage reservoirs, relative short pipelines are sufficient, with a cumulative length of approximately 20,000 km to store 15 Gt. 115,000 km of cumulative length is required for storage of all the point source

emissions. Comparison, for instance, with subclass E (only hydrocarbon fields are available for storage), shows that for the storage of 15 Gt over 100,000 km is required (see Appendix G). The availability of additional hydrocarbon fields in the 2020-scheme hardly influences the amount of carbon dioxide that can be stored at costs lower than 20 €/t or the total length of pipelines required. In contrast, the cumulative pipeline length required in subclass E with only hydrocarbon fields has changed, where the total pipeline length is half the amount in 2020-scheme compared to 2000-scheme. This is caused by the relative scarcity of hydrocarbon fields. The total costs for subclass A amount to 146 M€, i.e. average costs of 5 €/t. In Figure 6.3 the cost curve of subclass A is projected.

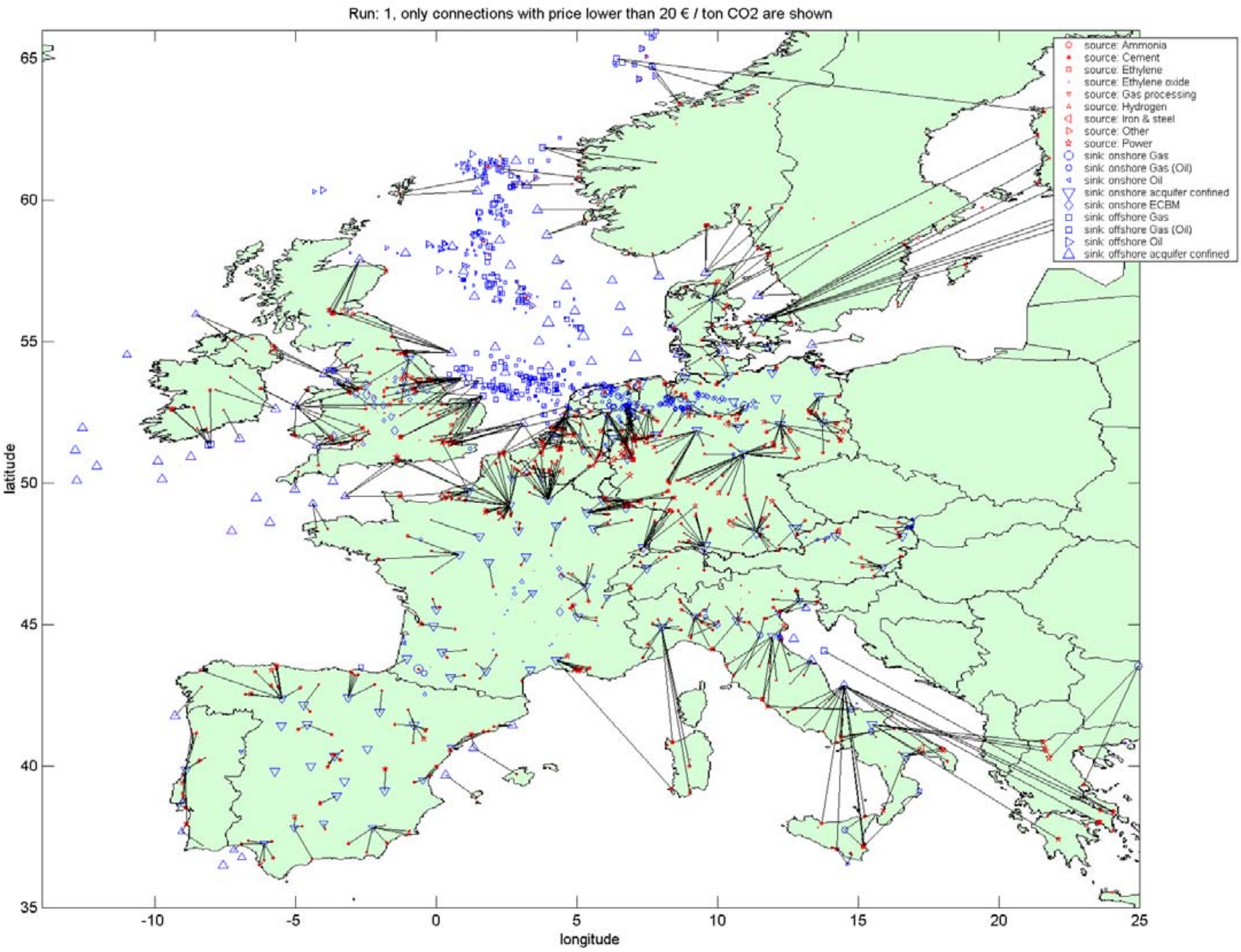


Figure 6.2. Pipelines from source to storage reservoir in subclass A 2000-scheme (excluding backbone)

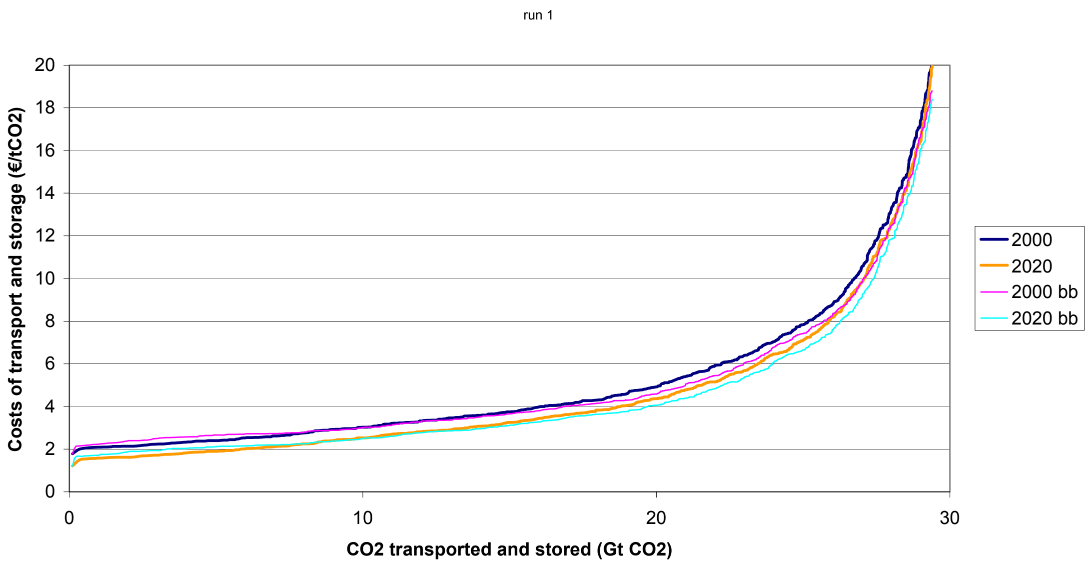


Figure 6.3. Cost curves for subclass A

6.3.2 Resulting transport-storage cost curves

For each of the above-mentioned subclasses Appendix G and Appendix H show:

- The map of Europe with the connections between sources – storage structures and the connections between source – backbone and backbone – storage structures (Appendix G);
- The associated cost curves for the defined schemes (Appendix G);
- The cumulative transport distances (Appendix H).

Table 6.3 Hydrocarbon fields, which are not available for carbon dioxide storage before 2020.

Country	Field name	Production	Off/onshore	CO_2 storage capacity (Mt)
UK	Brent	Oil and gas	Offshore	283
UK	Leman	Gas	Offshore	966
UK	Bruce	Gas and condensate	Offshore	204
UK	Britannia	Condensate	Offshore	207
DK	Tyra	Gas with thin oil zone	Offshore	206
No	Åsgard	Oil and gas with cap	Offshore	450
UK	Morecambe S	Gas	Offshore	656
No	6506/6-1	Gas	Offshore	230
NL	Groningen	Gas	Onshore	10100
No	6305/5-1	Gas and condensate	Offshore	918
No	Troll	Oil with gas cap	Offshore	4112
Total (Mt)				**18331**

Table 6.4 Overview of results for various transport-storage schemes in the 2000-schemes, bb = backbone transport pipeline

Run 2000	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**1bb**	**2bb**	**3bb**	**4bb**	**5bb**	**6bb**	**7bb**	**8bb**
Subclass	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
type of reservoirs	all	all	all	all	oil + gas	oil + gas	oil + gas	oil + gas	all	all	all	all	oil + gas	oil + gas	oil + gas	oil + gas
EOR applied in oil reservoirs	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR
onshore/offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore
backbone	no bb	no bb	no bb	no bb	no bb	no bb	no bb	no bb	Ruhr-London	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea
bb length (km)	-	-	-		-	-	-	-	695	3231	3231	3231	3231	3231	3231	3231
# source-store connections	1063	685	1073	700	490	235	524	273	898	405	830	394	129	30	214	106
# source-bb connections	-	-	-		-	-	-	-	209	499	304	529	345	185	271	132
# bb-store connections	-	-	-		-	-	-	-	6	18	29	51	504	367	464	325
Amount of CO2 to bb (Gt)	-	-	-		-	-	-	-	6.5	11.9	5.8	15.0	17.1	13.4	15.1	11.3
% of CO2 via backbone	-	-	-		-	-	-	-	22%	43%	20%	54%	83%	94%	74%	81%
avg store costs (€/t) (1)	-	-	-		-	-	-	-	2.10	4.25	1.30	3.80	9.19	10.56	7.35	8.15
avg bb costs (€/t)	-	-	-		-	-	-	-	0.28	1.20	1.29	1.19	1.18	1.19	1.19	1.21
avg total bb and store costs (€/t)	-	-	-		-	-	-	-	2.38	5.45	2.59	4.99	10.37	11.75	8.54	9.36
CO2 stored (Gt)	29.4	26.1	29.4	26.2	16.3	10.6	17.2	11.4	29.5	27.9	29.6	28.0	20.6	14.2	20.5	14.0
% stored	96%	85%	96%	85%	53%	34%	56%	37%	96%	91%	97%	91%	67%	46%	67%	46%
total costs (103 M€)	146	207	119	185	141	112	107	83	144	216	117	188	220	174	154	114
average costs (€/t)	4.97	7.93	4.05	7.06	8.65	10.57	6.22	7.28	4.88	7.74	3.95	6.71	10.68	12.25	7.51	8.14
Adjusted to same capacity																
Compared to run #	-	-	-		-	-	-	-	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Subclass	-	-	-		-	-	-	-	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
CO2 stored (Gt)	-	-	-		-	-	-	-	29.4	26.1	29.4	26.2	16.3	10.6	17.2	11.4
total costs (103 M€)	-	-	-		-	-	-	-	141	184	113	157	130	88.4	91	55.6
average costs (€/t)	-	-	-		-	-	-	-	4.80	7.05	3.84	5.99	7.98	8.34	5.29	4.88
cost difference bb and non-bb (M€)	-	-	-		-	-	-	-	5	23	6	28	11	24	16	27

(1) - cost to inject and monitor CO2 plus cost of transport from backbone to storage

(2) - this number shows the percentage of CO2 that can be stored and transported at a maximum costs of €20/t

Table 6.5 Overview of results for various transport-storage schemes in the 2020-schemes, bb = backbone transport pipeline

Run 2020	1	2	3	4	5	6	7	8	1bb	2bb	3bb	4bb	5bb	6bb	7bb	8bb
Subclass	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
type of reservoirs	all	all	all	all	oil + gas	oil + gas	oil + gas	oil + gas	all	all	all	all	oil + gas	oil + gas	oil + gas	oil + gas
EOR applied in oil reservoirs	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR	no EOR	no EOR	EOR	EOR
onshore/offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore	both	offshore
backbone	no bb	no bb	no bb	no bb	no bb	no bb	no bb	no bb	Ruhr-London	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea	Poland-North Sea
bb length (km)	-	-	-		-	-	-	-	695	3231	3231	3231	3231	3231	3231	3231
# source-store connections	1072	712	1097	736	624	327	714	338	901	400	875	428	267	37	336	161
# source-bb connections	-	-	-		-	-	-	-	213	521	270	517	601	588	565	490
# bb-store connections	-	-	-		-	-	-	-	6	13	33	58	42	380	59	316
Amount of CO2 to bb (Gt)	-	-	-		-	-	-	-	6.0	12.6	5.3	12.8	20.1	22.5	17.2	17.5
% of CO2 via backbone	-	-	-		-	-	-	-	20%	45%	18%	45%	75%	95%	63%	75%
avg store costs (€/t) (1)	-	-	-		-	-	-	-	1.56	3.35	0.68	2.90	2.52	7.43	2.00	5.60
avg bb costs (€/t)	-	-	-		-	-	-	-	0.28	1.20	1.31	1.20	1.17	1.16	1.18	1.18
avg total bb and store costs (€/t)	-	-	-		-	-	-	-	1.84	4.55	1.99	4.10	3.69	8.59	3.18	6.78
CO2 stored (Gt)	29.4	26.4	29.5	26.4	23.4	17.7	25.5	18.7	29.5	28.0	29.7	28.2	26.9	23.6	27.1	23.2
% stored	96%	86%	96%	86%	76%	58%	83%	61%	96%	91%	97%	92%	88%	77%	88%	76%
total costs (103 M€)	130	190	59.9	118	142	186	90	99	127	192	57	120	184	262	98	131
average costs (€/t)	4.42	7.20	2.03	4.47	6.07	10.51	3.53	5.29	4.31	6.86	1.92	4.26	6.84	11.10	3.62	5.65
Adjusted to same capacity																
Compared to run #	-	-	-		-	-	-	-	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Subclass	-	-	-		-	-	-	-	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
CO2 stored (Gt)	-	-	-		-	-	-	-	29.4	26.4	29.5	26.5	23.4	17.7	25.5	18.6
total costs (103 M€)	-	-	-		-	-	-	-	125	164	56	89	124	120	69	37
average costs (€/t)	-	-	-		-	-	-	-	4.25	6.22	1.88	3.34	5.30	6.76	2.71	1.98
cost difference bb and non-bb (M€)	-	-	-		-	-	-	-	5	26	4	29	18	66	21	62

(1) - cost to inject and monitor CO2 plus cost of transport from backbone to storage

(2) - this number shows the percentage of CO2 that can be stored and transported at a maximum costs of €20/t

In the Sections 6.3.3 and 6.3.4 we discuss the results when carbon dioxide capture and storage is implemented from now to about 2020 (2000-schemes). In section 6.3.5 we discuss the 2020-schemes results.

6.3.3 Schemes including all types of storage structures (subclasses A, B, C, D)

As can be seen from Table 6.4 (Run 1 and 1bb), when all storage reservoirs are available, close to 100% of the total emissions in 20 years (about 30.7 Gt CO_2) can be transported and stored at costs below 20 €/t (see also the criteria mentioned in Section 6.1.1). Fifteen gigatonne can be transported and stored at costs below 4 €/t CO_2. The total costs amount to over 146.10^3 M€, with an average cost of 5 €/t. When incremental oil production[15] is applied (Run 3 and 3bb), the net costs reduce to 119.10^3 M€ and average cost reduce to 4 €/t. Construction of a backbone does not influence significantly the costs results. In these cases only a fraction (20-22%) is transported by the backbone, the rest through project-based 1:1 pipelines.

If only *offshore* storage reservoirs are available without possibilities for incremental oil production (Run 2 and 2bb), the total amount that can be transported and stored is 26.1 Gt (85% of the total emitted carbon dioxide) at costs of 7.9 €/t (run 2). Construction of a backbone slightly increases the total amount that can be transported and stored to 27.9 Gt (91%) at costs of 7.74 €/t CO_2. When in the scheme with a backbone the same amount is transported and stored as in the scheme without backbone, i.e. 26.1 Gt, the costs in the backbone scheme reduce to 7.05 €/t CO_2.
When there is incremental oil production, costs are reduced on average by approximately 1 €/t.

6.3.4 Schemes with hydrocarbon fields (subclasses E, F, G, H)

If only hydrocarbon fields are available, the results change. In the case without incremental oil production, the percentage of CO_2 emissions that can be transported and stored at maximum costs of 20 €/t is 53% at a total cost of 141.10^3 M€ (without backbone, run 5) and 67% at a total cost of 220.10^3 M€ (with backbone, run 5bb). The costs for transporting and storing the additional 14% are relatively high; average costs increase from 8.65 to 10.68 €/t. If in both schemes (i.e. with and without backbone) the same amount is transported and stored, the specific costs decrease slightly with 0.5 €/t to 7.98 €/t CO_2 (see run 5bb). It can be concluded that in this case the defined backbone does not improve significantly the cost-effectiveness of transport and storage. Application of incremental oil production reduces average costs in all schemes with about 2.5 €/t.

If only *offshore* hydrocarbon fields are considered, the specific transport and storage costs increase with one to two euros, because less fields are available (run 6, 6bb, 8, and 8bb). When the same percentage (about 35%) is transported and stored in both schemes (with and without backbone), the construction of a backbone reduces costs by more than 2 €/t.

[15] The revenue for oil production is arbitrarily fixed at 20 euro per barrel of oil. This number is speculative and depends very much on the actual development of the oil price and the specific setting of the oil field.

6.3.5 Transport-storage costs projections in the year 2020

In this section we discuss the results when carbon dioxide capture and storage would be implemented from 2020 on. It is assumed that all hydrocarbon fields will be available and costs reductions have been obtained by progress in drilling technologies (see chapter 5).

From the numbers in Table 6.4 and Table 6.5 it can be concluded that considerably more can be stored at lower costs and considerably more at cost below 20 €/t. According to the results from runs 3/3bb and 4/4bb the extra amount to store in the 2020 calculation compared to the 2000 calculation is small, but average costs are considerably lower. On the other hand, runs 5/5bb, 6/6bb, 7/7bb and 8/8bb, dealing with hydrocarbon storage reservoirs, show a substantial increase in the percentage of carbon dioxide that can be stored at a cost below €20/t. This is not surprising as in 2020 a considerable amount of hydrocarbon-based storage capacity becomes available. In most cases, this increase in storage capacity is accompanied with substantial lower costs. In the cases that incremental oil production is not involved and all types of storage reservoirs are available (runs 1/1bb, 2/2bb), the costs difference and storage volume below 20 €/t is relatively small.
Application of a backbone reduces average transport and storage costs by one euro or less. An exception is when carbon dioxide is stored in offshore hydrocarbon reservoirs exclusively. In that case, construction of a backbone might well pay off.

6.3.6 Pipeline length requirements

For each scheme, the cumulative length of pipeline is determined relative to the cumulative amount of carbon dioxide to be transported and stored. The pipeline length includes the pipelines from source to storage, from source to backbone and from the satellite pipelines from backbone to storage. The graphs for each scheme are shown in Appendix H.

The cumulative length of pipeline varies from scheme to scheme and amounts to 30,000 km to over 150,000 km. The overall picture is that a backbone reduces the total length of pipeline, although this effect considerably varies among the schemes. The backbone reduces the cumulative length most significantly when only offshore reservoirs are used. When only hydrocarbon fields are used, the cumulative length is greater in schemes with backbone (compared with the schemes without) when smaller amounts of carbon dioxide are stored and the cumulative length is smaller when greater amounts are stored. The initial length of the backbone (plus satellite pipelines) that needs to be constructed explains this.

Remarkable is the observation that in the schemes with EOR the total length of the pipelines in 2020 are often greater than the total length in 2000 even when comparing the same amount of carbon dioxide to store. EOR offers such an attractive storage opportunity from an economical point of view that many pipelines are constructed apart from the backbone, just adding to the total pipeline length. With the availability of new fields in the 2020-schemes, this phenomenon is becoming even more important.

Notwithstanding the increased pipeline length, the total costs in 2020 are lower than in 2000.

7 Conclusions

The objective of the current IEA GHG study is to build cost curves for CO_2 transport and underground storage that are representative for OECD Europe. The storage options that have been included are:

- Storage in deep saline reservoirs
- Storage in depleted/disused oil and gas fields
- Storage in oil fields combined with oil production
- Storage in deep unminable coal seams with coal-bed methane production

Availability and representativity of geological data

The best dataset is available for oil and gas fields in Europe, which is not surprising considering the effort that oil and gas industry put in hydrocarbon exploitation in Europe. The availability of hydrocarbon production data depends on national regulations, which differ from country to country. The GESTCO-project already resulted in a useful dataset for the hydrocarbon fields. This data was expanded with information from the earlier Joule II project and a limited inventory within the scope of the present project. For the calculation of possible additional oil production assumptions had to be made for various parameters like the API gravity.

The quality of the available datasets for European deep saline aquifers and deep unminable coal seams was far less. The GESTCO data with different levels of detail refer to limited areas within Europe. For the deep saline aquifer option, a complete dataset with a very low level of detail had to be compiled for this specific project. This dataset in fact is a digital representation of the extent of sedimentary basins in Europe.

Data for the deep unminable coal seams were gathered from different sources, e.g. the GESTCO project, the IGCP project 166 and an additional inventory in the present project. Shallow coal mining data are not directly applicable to the depth window of 800 to 1500 m, which is of interest here. Critical parameters like coal permeability are almost completely lacking.

Storage capacity

The presented numbers for the storage capacity are associated with significant uncertainties, in particular for the aquifer option. Because site-specific data were missing, the estimates had to be based on simple calculations with quite a number of assumptions.

The type of aquifer storage concept that is used clearly affects the calculated geological storage capacity. Depending on the type of deep saline aquifer (confined or unconfined) and the CO_2 phase (free gas or dissolved) in the deep saline aquifer, the storage capacity of European deep saline aquifers is estimated at 150 to 1500 Gt of CO_2. No estimate was made of the storage capacity in individual deep saline aquifer traps, which is beyond the scope of the current project.

The total capacity of hydrocarbon fields in OECD Europe is calculated at more than 40 Gt CO_2, 7 Gt of which can be stored in oil reservoirs. A technical (not economic!) evaluation of possible associated oil production resulted in an additional oil volume of about 2.10^9 m^3, which is more than 10 billion barrels of oil. Most individual hydrocarbon fields have a storage capacity of less than 50 Mt CO_2. A few exceptional giants like the Groningen gas field have a storage capacity of more than one Gt CO_2.

The storage capacity of European deep unminable coal seams at a depth of 800 to 1500 m is estimated at about 6 Gt CO_2.

Stationary CO_2 emission sources

The database holds information on more than 1900 individual point sources in Europe, of which almost 60% account for 99% of the total CO_2 emission from point sources. The total emission is approximately 1.5 Gt on an annual basis. Two third of the point sources is related to power generation. 22 Mt of pure CO_2 is emitted annually, mostly from ammonia plants.

CO_2 sources are not spread equally through Europe; they are often concentrated in clusters like in the German Ruhr area or the Dutch Rijnmond area. This will have an effect on the CO_2 transport infrastructure.

Equipment and costs

The equipment for transport consists of the following elements:

- Pipeline infrastructure
  - Booster station(s) depending on transport distance and pipe diameter
  - Safety valves
  - Shut-down devices
  - Pressure monitoring device
  - Specific measures for crossing water and roads
- Control centre
  - Telecommunication

Investment costs for pipeline transport vary from 0.2 million (± 60%) to 1 million euro (± 40%) per km for pipelines of 20 cm to 1.2 m in diameter, respectively. The transport cost per tonne of CO_2 varies from less than 1 euro to more than 20 euro as a function of the transport distance (100 to 1500 km) and the CO_2 mass flow.

The equipment for underground storage consists of:

- Cased well
- Injection tube
- Well head
  - SCADA safety device
  - Remote control
- Offshore surface installation
  - Platform or sub-sea completion
- Monitoring devices like:
  - Observation well

- Time-lapse seismic surveys
- Seismometers

Storage costs range:

Storage option	Minimum (€/tCO_2)	Maximum (€/tCO_2)	Percentage storage capacity
Deep saline aquifers	0.60	5	90%
Gas fields	0.75	5	90%
Oil fields	1.50	7.5	80%
Oil fields *without* oil production revenues	6	40	80%
Oil fields *with* oil production revenues (20 €/barrel)	-40	20	-
Coal seam without methane revenues	20	50	-

Transport-storage cost curves

In generating cost curves for transport and storage of CO_2 two types of transport infrastructure have been considered:
- Decentral transport infrastructure linking individual sources with individual storage structures (1-1 approach);
- Central main transport infrastructure linking more sources and storage structures (backbone approach).

Both types of infrastructure have been analysed for various combinations of storage options. The used cut-off value for the transport-storage costs is 20 €/tonne CO_2 and the assumed lifetime of a storage facility is 20 years. The calculations are performed for two schemes: 2000-scheme and 2020-scheme. The first scheme assumes implementation under current knowledge and technology level, and not all hydrocarbon fields are already available for carbon dioxide storage. In the second scheme all hydrocarbon fields are available for storage, and storage costs have decreased due to improved drilling technologies. No cost reductions are assumed for pipeline construction.

When all storage structures are available close to 100% of the 20-year emissions can be stored (≈ 30 Gt CO_2), 20 Gt of which can be transported and stored for up to 4-5 €/tonne CO_2. The total costs amount to 146 billion euro. Insignificant cost reducing effect by implementation of a backbone was seen.

Not all emitted CO_2 can be stored when storage is restricted to the hydrocarbon fields: 53% without backbone and 67% with backbone. The costs per tonne CO_2 are higher, namely 8.65 euro without backbone and 10.68 euro with backbone. The total costs are 141 and 220 billion euro, respectively. Assuming that the same amount is stored in the backbone variant, the construction of the backbone reduces the costs by 11 billion euro. Average costs are then 7.98 €/t.

The backbone transport infrastructure becomes financially more attractive when storage is restricted to offshore hydrocarbon fields. The backbone reduces costs on average by about 2.5 €/t.

Incremental oil production decreases the costs per tonne of CO_2 varying between 0.5 and 3 euro depending on the storage scheme applied.

When storage takes place after 2020 the costs will decrease due to lower drilling costs and due to that hydrocarbon fields will become available in the next 20 to 40 years. The difference in costs between the 2000-scheme and the 2020-scheme varies between 0.5 euro and 3 euro per tonne of carbon dioxide. The highest costs difference is seen when storage is restricted to hydrocarbon fields. Another important effect is that much more carbon dioxide can be stored at costs below 20 €/t.

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A Data sources for storage structures in OECD Europe

The table below gives an overview of potential data sources for underground CO_2 storage options in the countries of OECD: I = IEA GHG report (2002); G = GESTCO GIS (Christensen & Holloway, 2003); IGCP = Int. Geol. Correlation Project 166 (1980). If additional inventories were needed this has also been indicated.

Country	CO_2 source data	Hydrocarbon data	Black coal data[16]	Deep saline aquifer data
Iceland	I	no hc[17]	no coal	no suitable aq.
Norway	G	G	no coal	Add. Invent./G
Sweden	I	no hc	no coal	Add. Invent.
Finland	I	no hc	no coal	no aquifer
Denmark	G	G	no coal	Add. Invent./G
Ireland	I	Add. Invent.	IGCP	Add. Invent.
Great Britain	G	G	G	Add. Invent./G
Netherlands	G	G	G	G
Belgium	G	no hc	G	G
Luxembourg	I	no hc	no coal	no suitable aq.
Germany	G	G	G/no suitable coal?	G
France	G	Add. Invent.	IGCP	G
Austria	I	Add. Invent.	no coal	Add. Invent.
Switzerland	I	Add. Invent.	no coal	Add. Invent.
Portugal	I	no hc	no suitable coal	Add. Invent.
Spain	I	Add. Invent.	Add. Invent.	Add. Invent.
Italy	I	Add. Invent.	Add. Invent.	Add. Invent.
Greece	G	G	No coal	Add. Invent.

[16] Black coal includes anthracite, bituminous coal and sub-bituminous coal but excludes lignite.
[17] hc = hydrocarbons.

B Review of additional deep saline aquifer data

The starting point for the present study is formed by the results from the GESTCO project (Christensen and Holloway, 2003), which covers selected parts of Europe, and by the results from the earlier Joule II project (Holloway, 1996). Appendix B provides a review of deep saline aquifer data for European countries that were not treated in the GESTCO or Joule II studies.

B.1 Deep saline aquifers in Austria

There are three major sedimentary basins in Austria; the Molasse Basin, the Vienna Basin and the Styrian Basin. These areas are considered to have the most potential for CO_2 storage in deep saline aquifers. The Molasse Basin and the Vienna Basin also contain Austria's petroleum resources.

B.1.1 Molasse Basin

The Molasse basin is a Cenozoic foreland basin lying to the northwest of the Alps and SW of the Jura. It is located in France, Austria, Switzerland and Germany. It is about 700 km long and a maximum 150 km wide (in southern Germany). The basin is up to 4 km deep at its deepest point. The cities of Geneva, Berne, Zurich and Munchen lie on top of it.

Deep confined groundwater is only rarely tapped at depths greater than 250 m in the Molasse Basin, so there is unlikely to be a conflict of use between the water industry and CO_2 storage unless there is considered to be a risk of upwards leakage of carbon dioxide.

The Eocene to Pliocene (predominantly Oligocene to Upper Miocene) clastic sediments that comprise the Molasse Basin fill were deposited above a pronounced unconformity. The Miocene (Ottnangian) gravels and sands (United Nations, 1991) are the most important deep saline aquifers within the Basin. However, minor deep saline aquifers also occur in the Pliocene and Upper Oligocene. There are very good quality reservoir rocks and seals within the Molasse Zone in Austria (Janoschek et al., 1996).

There is a sedimentary succession below the Molasse Basin. It consists of Middle Triassic to Upper Cretaceous shallow marine carbonates that were deposited on a passive margin, with a total thickness varying from 1 to 2.5 km. Important deep saline aquifers occur, in karstified Malm (Jurassic) limestones and dolomite, and in Malm sandstones and Cenomanian sands. Minor deep saline aquifers occur in the Upper Cretaceous (Campanian - Turonian) sandstones. The Malm can be up to 500 m thick. These reservoirs could have CO_2 storage potential but there is not enough information available to confirm this at present.

The Mesozoic passive margin series rests unconformably on crystalline basement similar to that found in the surrounding Vosges, Black Forest and Massif Central.

Summary
There is potential in several reservoirs. For resource calculation purposes it is assumed that on average one reservoir is present throughout the area of the basin below 700 m.

B.1.2 Vienna Basin

The Vienna Basin is described in detail in 'Erdol und Erdgas in Osterreich' (OMV 1993). It is of Lower Miocene and younger age and is up to 5.5 km deep.

Lower Miocene reservoir rocks
The oldest reservoir rocks occur in the Lower Miocene strata. In general, these are isolated sand bodies and lenses surrounded by clay-rich sediments. Speculatively, these may not be ideally suited for CO_2 storage because, although they are well sealed, they may be too well sealed to allow large quantities of CO_2 to be injected without unacceptable pressure rise.

Middle to Upper Miocene reservoir rocks
Apart from the basal Aderklaa Conglomerate, the Middle to Upper Miocene reservoir rocks are deltaic sand layers which are interbedded with shales that form seals. The average porosities increase upwards from 20-25% to 28-30%. These reservoirs are likely to have enough porosity and permeability to act as CO_2 storage reservoirs, and they occur at the right depth over much of the basin. The most prolific of these sand layers, known as 16-TH, has an average net pay of 50 m and 25% average porosity (Seifert, 1996).

OMV (1993) show a detailed map of the top of the Sarmatian interval (close to the top of these reservoir rocks). The areas, in which the top Sarmatian occurs at depths >700 m below sea level together, cover about 800 km^2.

Summary
Clearly some potential but needs a local expert to quantify properly.

B.1.3 Styrian Basin

The Styrian basin, which is about 100 km long and 60 km wide, is located about 40 km southeast of the Alps, in the area southeast of Graz. It is just contiguous with the larger Pannonian Basin that occurs mainly in Slovenia and Hungary. The two basins are almost separated by the South Burgenland Ridge and are distinct in terms of their structural and sedimentary history (Janoschek et al.1996). It is filled with Miocene and younger rocks and also contains significant amounts of volcanic rocks in places. The western half of the basin, the West Styrian Basin, is <500 m deep and therefore unsuitable for CO_2 storage in the dense phase. The eastern part, comprising the Gnas and Furstenfeld sub-basins, is more than 3000 m deep and may be more than 4000 m deep at its deepest point (Sachsenhofer et al. 1996). The eastern boundary of the Styrian Basin that separates it from the main Hungarian Pannonian Basin is taken at the South Burgenland Ridge. Beneath the basin are crystalline and very low grade metamorphic Palaeozoic rocks that have no potential for CO_2 storage (Sachsenhofer et al. 1996).

There may be some potential for CO_2 storage in this basin, but this may give rise to conflicts of interest with the groundwater and geothermal energy industries. Groundwater is produced from the shallower aquifers of the Styrian Basin. However, at present, deep confined groundwater is only rarely tapped at depths greater than 250 m. Two former oil exploration wells are now used as thermal spas (Sachsenhofer et al. 1996).

Reservoir rocks are present but their distribution is poorly known. The lack of any detailed maps of reservoir rocks in the Styrian Basin means that no CO_2 storage potential can be defined at present.
However, a boring in the Styrian Basin showed clay-free water-bearing sand beds separated by thick clay and marl layers and covered by a clay and marl series with thick sandstone layers at a depth of 1540-1675 m. Log correlation with adjacent boreholes show that these layers are quite extensive. The temperature in the formation is about 70 °C (UN 1991). Thus these sandstone beds potentially form an important source of geothermal energy. The high geothermal gradient in the Styrian Basin means that CO_2 would be stored at lower densities than in many other basins.

Summary
Potential too poorly known to quantify and there is potential for conflicts of interest with geothermal energy production.

Other issues
In Austria virtually all drinking water originates from groundwater sources (locally supplemented by surface water). This is mainly supplied to towns from shallow, sometimes distant, sources e.g. in the Alps.

B.2 Deep saline aquifers in Switzerland

The deep saline aquifers of Switzerland are still poorly known. However, those in the northwest of Switzerland they are being systematically studied as part of a project to dispose of radioactive waste in the crystalline basement.

Most is known about the deep saline aquifers that occur in and beneath the Swiss part of the Molasse Basin. They are:

- Upper Marine Molasse (of Cenozoic age and within the basin)
- Karstified Mesozoic limestone of Cretaceous and Jurassic age, known as the Malm (beneath the basin)
- Upper Dolomitic Muschelkalk (of Triassic age and beneath the basin)
- Lower Buntsandstein (Triassic and beneath the basin) and the altered surface of the crystalline basement

However, it is considered likely that there would be a conflict of interest that might prevent CO_2 storage in or beneath the Swiss part of the Molasse Basin because all these reservoirs are used for thermal and mineral water production. The Upper Marine Molasse has been used in recent times for the production of mineral and thermal water at Zurich and on the Swiss shore of Lake Constance. Oil exploration drilling has revealed the presence of active water circulation in the (karstified) limestone series of the Cretaceous and Malm. These are the subsurface continuations beneath the Swiss

Plateau of strata that provide groundwater in the Jura. Water from this deep saline aquifer is used at the thermal spa in Yverdon-les-Bains. The thermal-mineral springs of Baden, Schinznach and Lostorf come from the Muschelkalk. The waters of the Buntsandstein and basement rocks are extracted at Zyrzach. The potential for development of geothermal energy from these reservoirs is being studied.

In Switzerland there is a powerful and effective Federal Law on groundwater protection. Because of the federal political structure of Switzerland, hydrogeological exploration and the management and protection of deep saline aquifers is primarily the responsibility of the cantons.

Thus it is considered that there is little realistic prospect of CO_2 storage in the Swiss part of the Molasse Basin in the foreseeable future.

Summary
No resource should be quantified at present due to legal issues and potential conflicts of use of the subsurface.

B.3 Deep saline aquifers in Spain

Most of the Iberian Peninsula comprises a Hercynian basement overlain by a thin sedimentary cover, and is known as the Meseta. North and South of the Meseta are strongly folded and faulted mountain ranges; the Pyrenees in the north and the Betic Cordillera in the south.

However, there are a number of sedimentary basins that may have some potential. These are the:

- Ebro Basin
- Guadalquivir Basin
- Mula Basin
- Campo de Cartagena Basin
- Duero (=Castilla la Vieja) Basin
- Tajo (= Castilla la Nueva = Madrid) Basin
- Gulf of Valencia Basin

B.3.1 Ebro Basin

The Tertiary Ebro Basin, located in the north-eastern part of the Iberian Peninsula, is framed by three mountain ranges, the Pyrenees to the north, the Iberian Chain to the south-west, and the Catalonian Coastal Ranges to the south-east. The Ebro Basin is the southern foreland basin of the Pyrenees. It was formed in Palaeogene (early Cenozoic) times. It is asymmetric; the thickness of the basin increases northwards, reaching 4000 m adjacent to the Pyrenees. The individual stratigraphic units that fill the basin also increase in thickness northwards. Most of the strata are of Eocene age and these are overlain by continental Oligocene and Miocene 'molasse'-type deposits.

Carbonate reservoir rocks occur in the Eocene section. These originated from the sliding of large masses of material off the Pyrenees to the north, into the basin. They are chaotic fractured and slumped strata. They are best developed in the Jaca sub-basin (Melendez-Hevia & Alvarez de Buergo 1995) in the north-central part of the basin. Here they occur at depths of around 1600-1700 m and 2500 m. Their porosity is only 5 - 8%. Their permeability is not quoted by Melendez-Hevia & Alvarez de Buergo (1995) and although intergranular permeability is likely to be far too low for CO_2 storage, the presence of fractures gives hope. However any potential for CO_2 storage is purely speculative. It is of geothermal interest as its temperature varies between 150-180 °C at 2800-3600 m.

Summary
No quantifiable CO_2 storage potential as permeability of reservoir rocks is not known and likely too low.

B.3.2 Guadalquivir Basin

The Guadalquivir Basin is a Miocene foreland basin that lies to the north of the Betic Cordillera. It continues westwards offshore into Spanish and then Portuguese waters, where it is known as the Algarve Basin. It is relatively shallow, the basement being at depths of only about 500 m at its eastern end, deepening to about 1500 m at the Spanish west coast. It is deepest on its south side, adjacent to the Betic Cordillera. It is filled with marine marls of Miocene and younger age that contain sandy intercalations. These overlie a basal calcarenite that rests on pre-Miocene basement. The stratigraphy near the southern margin is more complicated as the basin fill contains major chaotic rock masses that originated as gravitational slides that slid off the Betic Cordillera (Fernandez et al., 1998), the Olistostroma nappe of Fernandez et al. (2002).

Within the basin there are sand bodies surrounded by shales, some of which form small gas fields. They are found at four stratigraphic levels. The sands are sealed laterally as well as vertically but there is some communication between them because at any locality it tends to be the uppermost sand body that contains natural gas. Thus for the purposes of CO_2 storage, they can probably be treated as a single reservoir. Melendez-Hevia & Alvarez de Buergo (1995) do not indicate the porosity or permeability of these sands.

A Jurassic limestone geothermal reservoir underlies part of the basin and is well known from oil exploration wells. It occurs at depths of 300-3000 m. Thickness varies from 250-1000 m. The porosity is up to about 16-19% and the temperature of the reservoir varies from about 50-75 °C (Fernandez et al., 2002). This reservoir may also have some potential for CO_2 storage if the permeability is high enough.

Summary
Two reservoirs with potential for CO_2 storage - permeability and distribution within basin not known but both are assumed to cover 50% of the basin area.

B.3.3 Duero Basin

This Basin lies in the north of Spain between the Iberian Chain and the Cantabrian mountains. It is centred around the town of Valladolid. It is filled with Cenozoic terrigenous deposits with a maximum thickness of 2000 m. Three sedimentary units separated by unconformities can be distinguished, the lower two of which occur beneath the Cenozoic basin:

- The Triassic and Jurassic. The Triassic is thin and mainly detrital. The Jurassic consists mainly of platform carbonates.
- The Cretaceous. The Jurassic is overlain by Lower Cretaceous fluvio-deltaic conglomerates, sandstones and siltstones, followed by Upper Cretaceous marine limestones.
- The Cenozoic basin fill - this comprises continental clays, limestones and evaporites.

Summary
The apparent lack of sandstones suggests that there may be little CO_2 storage potential in this basin, but further research is needed to quantify this.

B.3.4 Tajo (=Madrid) Basin

The Neogene sedimentary fill of this basin reaches a maximum thickness of about 3500 m and is commonly around 2000 m thick. During most of the Miocene the basin was occupied by lakes and peripheral alluvial systems, producing a concentric facies distribution, with the better reservoir rocks occurring around the basin margin and being absent in the basin centre. In the Late Miocene more sandy strata were deposited in the basin centre, but these are at shallow depths and connected to the surface via similar but thin overlying Pliocene strata.

The inference from the scant information available is that the CO_2 storage potential of the Tajo Basin may be limited by the lack of good quality reservoir rocks in the deeper parts of the basin.

Summary
Any CO_2 storage potential is not quantifiable on the basis of the above information. Further research on reservoirs and seals needed.

B.3.5 Gulf of Valencia (Mediterranean) Basin

This Basin is the offshore continuation of the (relatively small) Catalonia Grabens. It is an extensional basin lying between the east coast of the Spanish mainland and the Balearic Islands. The water depth increases rapidly away from the mainland coast, so only a narrow strip of the basin adjacent to the mainland has been considered as suitable for CO_2 storage, on the grounds that operating in very deep water (>500 m) would be prohibitively expensive. Geologically, the mainland margin shows typical features of a rifted margin; well developed horsts and graben bounded by ENE-WSW to N-S oriented faults. The basin is filled with Late Oligocene to Quaternary strata up to 6 km thick.

The Gulf of Valencia Basin contains at its base an important reservoir rock; the karst zone of the Mesozoic carbonates (Melendez-Hevia & Alvarez de Buergo 1995). Clavell & Berastegui (1991) indicate that the karstifed zone has a thickness of about 50 m and a porosity of 10-20%. This zone forms the reservoir in the Casablanca field and other nearby oilfields. The presence of oilfields indicates a good seal. It is sealed by either the

Miocene Alcanar group or the shales of the Miocene Castellon Group. Barbier (1996) estimated the CO_2 storage capacity of this reservoir to be 6 Mt.

Summary
Good potential in karstified Mesozoic carbonates at base of basin. Effectiveness of seal is proven by the presence of oil fields. Distribution is not known but assumed to cover 50% of the accessible basin.

B.3.6 Mula Basin

This basin is about 20 km NW of Murcia in SW Spain. It appears to be marginal for CO_2 storage. A middle Miocene calcarenite reservoir rock is present at depths of 100 - 1200 m. Total thickness ranges from 100-300 m in a few places. The porosity is 10% and the temperature in the reservoir ranges from 30 – 70 °C.

Summary
One potential reservoir rock but no resource can be quantified at present.

B.3.7 Campo de Cartagena Basin

This basin is on the Mediterranean coast around Cartagena, south of Alicante. It may have some marginal potential for CO_2 storage but the deep saline aquifers within it are connected, suggesting that there may be seal problems. Structurally it is a graben. Both the Jurassic limestone and the Middle Miocene calcarenite are potential geothermal reservoirs. The Jurassic limestone reservoir extends from the surface to depths of >1000 m. Porosity ranges from 6-9% and may be a limiting factor for CO_2 storage. The temperature in the deep saline aquifer is 25 - 30°C.

Summary
Two possible reservoir rocks but porosity and thus permeability is likely to be too low for CO_2 storage. No resource should be quantified at present.

B.4 Deep saline aquifers in Italy

The geological structure of Italy is extremely complex and it is difficult to define succinctly the potential for storing CO_2 either onshore or offshore. However, the best reservoir rocks are almost all of Cenozoic (more precisely post-Eocene) age. The older Eocene to Mesozoic rocks are carbonates that do have some reservoir potential but their porosity is commonly low and permeability is mainly from fractures. Whilst they may have fair porosity and permeability characteristics locally, they may not have the necessary characteristics for large scale CO_2 storage regionally (see below). Older strata probably also have low CO_2 storage potential. Thus the best potential is probably in the deeper Cenozoic sedimentary basins.

The main Cenozoic sedimentary basin in Italy is the Po Basin, which lies beneath the plain of Lombardy and extends offshore into the Adriatic Sea. It is contiguous with the shallower Veneto Basin which lies on the north coast of the Adriatic around Venice and with Cenozoic strata that occur on the east coast of Italy in the Pedeappeninic Basin and offshore on the Central Adriatic - Apulia Platform (ECE Committee on Gas, 1984).

B.4.1 The Po Basin

The Po Basin covers an area onshore of 46,300 km^2 and continues offshore into the Adriatic. Onshore it is 420 km long and 90 - 270 km wide. It contains Italy's largest and most important deep saline aquifers.

The sedimentary sequence in the Po Basin consists of 26 rock units. Twenty of these are aquifers and six are aquicludes (Baldi et al., 2002). The deep saline aquifers can be grouped into 2 large systems; the Continuous Aquifer System (the porous and permeable formations in the post-Eocene sedimentary succession) and the Discontinuous Aquifer System (the older, Mesozoic to Eocene carbonate rocks). The Discontinuous Aquifer System commonly has low porosity but has a pronounced fracture system in some areas.

The Continuous Aquifer System
The shallowest aquifers in the Continuous Aquifer System are commonly grouped together because they are not separated by regional aquicludes. Collectively they are known as the 'Multi-layer Complex of the Continental Quaternary'. They comprise sands and gravels that occur at or relatively near the ground surface down to a depth of about 500 m. They have no potential for CO_2 storage because there are no significant aquicludes to prevent the escape of CO_2 to the ground surface, and they do not reach 700 m depth.

The 'Multi-layer Complex of the Continental Quaternary' generally rests on the Asti Sand aquifer. This is of Plio-Pleistocene age. It cannot be considered to have significant CO_2 storage potential because it is in hydraulic continuity with the Multi-layer Complex of the Continental Quaternary (Rizzini & Dondi, 1979).

Beneath the Asti Sand is the Santerno Clay Formation, a thick aquiclude which, judging from the cross sections presented by Rizzini & Dondi (1979) and Baldi et al. (2002), seals the underlying Pliocene-Messinian deep saline aquifer towards the margins of the Po Basin. However, in the centre of the Basin, the Pliocene-Messinian deep saline aquifer appears to be contiguous with, and thus possibly hydraulically connected to, the Asti Sand and Quaternary deep saline aquifers.

The Pliocene-Messinian Deep saline aquifer
The Pliocene-Messinian deep saline aquifer comprises the Caviaga, Cortemaggiore, Sergnano, Fusignano, Sartirana and Boreca Formations. It is >1000 m deep except on the crests of anticlines and in the Pedealpine homocline. The distribution of these formations is shown in Rizzini & Dondi (1979). The Fusignano Formation may extend offshore into the Adriatic but there its distribution is not known.

The Caviaga Sand Formation consists of thick sands with clay interbeds and rare gravel horizons. The average thickness of the Formation is 100-200 m. It is developed in a small area southeast of Milan.

The Cortemaggiore Sand Formation is similar to the Caviaga Sand. It is usually less than 100 m thick.

The Sergnano Gravel Formation consists mainly of conglomerates and is 200-300 m thick. It occurs on the northern side of the Basin around and to the east of Milan. There is 20% porosity in the Sergnano Formation (Barbier, 1996).

The Fusignano Formation and Sartirana Formation are probably laterally equivalent, occurring respectively east and west of the San Colombano High. They consist of irregularly interbedded very thick sands and clay interbeds of highly variable thickness. They also contain a few conglomeratic levels. They are thought to be turbidites. The Fusignano Formation is always thick and may reach 1000 m. The Sartirana Formation may reach 500 m.

The Boreca Formation is a thick conglomerate with a restricted distribution close to the coast. It consists of conglomerate and anglar breccias with thin marl interbeds. Its thickness is very variable, ranging from a few tens of metres to several hundred metres.

The underlying deep saline aquifers are the lowest in the Continuous Aquifer Unit. They comprise the Gonfolite, Ottobiano, Serravale and Marnoso-Arenacea Formations, of Oligocene to Tortonian age. These seldom occur above 1000 m depth, often have low permeability and pass laterally into the Gallare Marl mudstone unit. The Gallare Marl is the basal aquiclude that separates the Continuous Aquifer Unit from the underlying Discontinuous Aquifer Unit (Baldi et al. 2002).

Thus the best deep saline aquifer for CO_2 storage is likely to be the Pliocene to Messinian deep saline aquifer, because it is deep enough and the accounts of Baldi et al. (2002) and Barbier (1996) imply it may have significant permeability.

The Discontinuous Aquifer System
This consists of the carbonate rocks that occur below the Continuous Aquifer System. It is widespread through much of Peninsular Italy, and is not restricted to the Po Basin. Permeability relies mainly on fractures. Porosity is low; 2-3% at the Malossa field, 4% in the Gela and Ragusa oilfields (Sicily; see also Section B.3.1) and low in the Emilia and Emma offshore fields. The only significant porosity is in the Siracusa Formation, host to the Vega oilfield, where it is 11-16% (Barbier, 1996). The generally low porosity probably rules it out as a suitable reservoir for CO_2 storage.

Potential conflicts of interest
The Po Basin is a priority area for exploitation of low enthalpy geothermal resources (geothermal resources found in deep saline aquifers) so there may be conflicts of interest here.
There are approximately 40,000 water wells in the Po Basin, most of which are fairly shallow. The groundwater mainly comes from the so-called Continuous Aquifer System. This comprises sands and gravels that occur at or relatively near the ground surface down to a depth of about 500 m. The zone of potential CO_2 storage interest is below this. Nevertheless, there is a potential conflict of interest with the groundwater industry.

Summary
The CO_2 storage capacity of the Po Basin is based on the following assumptions:
Only the Pliocene to Messinian deep saline aquifer has CO_2 storage potential. Higher aquifers are too well connected to the surface and fresh water aquifers. Deeper saline aquifers have too low permeability. The Pliocene to Messinian deep saline aquifer covers an area of about 5000 km^2.

B.4.2 The Veneto Basin, Pedeappeninic Basin and Central Adriatic - Apulia Platform

The Veneto Basin, Pedeappeninic Basin and its continuation offshore on the Central Adriatic - Apulia Platform may have some potential for CO_2 storage. However, they are shallower than the Po Basin and therefore probably have significantly less potential. Any potential is not quantifiable within this study.

Summary
No quantifiable CO_2 storage capacity

B.4.3 Other areas (the Alps, Appennines and islands)

The Alps
The Alps probably do not contain deep saline aquifers suitable for storing CO_2. The Italian high Alps are mainly composed of crystalline rocks which have insufficient permeability to form good reservoirs. Gravel and sand aquifers occur in the Alpine Valleys but these are probably not deeply buried enough to store CO_2 in the dense phase. Nor are they likely to be capped by reliable cap rocks.

Karstified limestones and dolomite aquifers are abundant, but their structure at depth is poorly known and their potential (if any) for storing CO_2 is very hard to assess.

Summary
Any CO_2 storage capacity not quantifiable at present

B.5 Deep saline aquifers in Portugal

Continental Portugal may be divided into 4 geological domains:

- The Western Massif
- The Western Middle Cenozoic Fringe
- The Southern Fringe (or Algarve Basin)
- The Lower Tagus and Sado sedimentary basins

The Western Massif, the Portuguese part of the Iberian Meseta, which continues eastwards into Spain, occupies about three quarters of Portugal. It is made up of pre-Mesozoic (Variscan) igneous and metamorphic rocks. These rocks probably have no potential to store carbon dioxide underground - they contain hardly any porous deep saline aquifers.

The Western Fringe occupies the coastal areas between Sagres and Vila Real del Santo Antonio in the south and Espinho and Sines to the west. This domain contains a highly diverse succession of mainly sedimentary rocks, of Triassic to Recent age, up to 3000 m thick. It was formed in a tectonic trench caused by the sinking of the most western part of the Iberian Massif.

The karstified limestone formations of the Middle Jurassic form the best deep saline aquifers in the Western Fringe. They provide important reservoirs of water for the Lisbon area. Lower Cretaceous detrital rocks also form a good deep saline aquifer, especially in the southern part of the Western Fringe.

The Southern Fringe of the Algarve Basin is only a few kilometres wide onshore. It forms the northern edge of the predominantly offshore Algarve Basin, which is the eastwards continuation of the Spanish Guadalquivir Basin. It increases in thickness gradually towards the south. Onshore, the most important deep saline aquifers are the intensely karstified Lower Jurassic limestones. These contain the main groundwater reserves of southern Portugal and thus cannot be used for CO_2 storage onshore. Groundwater is the only source for domestic supply in this region.

The sedimentary basins of the Tagus (Tejo) and Sado are made up of Oligocene to Recent formations. The strata are practically horizontal and they contain the best groundwater reservoirs in Portugal, with depths attaining 500 m. The main deep saline aquifer complex is of Miocene and Quaternary age. The individual deep saline aquifers are related from the hydraulic point of view and may be considered for practical purposes as a single deep saline aquifer system. This deep saline aquifer system is not suitable for CO_2 storage because it is too shallow and, in any case, it is the main source of groundwater supply for the region. However, the Jurassic and Cretaceous rocks beneath this basin might be of interest for CO_2 storage:

- The Jurassic limestones underlie the Tertiary sedimentary basin and they are of little interest for groundwater abstraction because of their depth. In the Setubal peninsula they are at depths >1000 m. North of the Tagus, they are depths of about 500 m or more.

- Aptian-Albian and Valanginian reservoir rocks with geothermal potential occur above the Jurassic limestones and below the main Tertiary sedimentary basin.

  The Aptian-Albian reservoir is the Gres de Almargen. It comprises mainly siliceous sandstones. For geothermal purposes the porosity of this sandstone is assumed to be 15%. The distribution of the sandstone is poorly defined; however it occurs at depths of 1200-1450 m in well AC1-BALUM (Correia & Ramalho 2002) where it is steeply dipping.

  The Valanginian deep saline aquifer. These formations are hydraulically independent of the Tertiary deep saline aquifers that lie above them because the thickness and low permeability of the intervening Oligocene - Cretaceous strata make the circulation of water between them difficult.

Therefore it appears that the best potential for CO_2 storage may occur in the karstified Jurassic limestones where they lie at depth beneath the southern and western fringes and the Tagus/Sado sedimentary basin. However, there is little evidence to support this statement. There are no maps available that show the depth of these formations, and no information on whether they are karstified at depth - evidence from offshore (see below) suggests not. Calculation of resources is impossible without much more than these minimum data.

Summary
The Cenozoic basin shows no potential; any potential in the strata below it is not quantifiable at present.

B.6 Deep saline aquifers offshore Portugal

There are 4 basins offshore from Portugal. The largest is the Lusitanian Basin. This is the offshore continuation of the Western Fringe. To the north of this lies the Porto/Galicia Basin which is completely offshore. To the south are the Alentejo Basin (which is completely offshore) and the Algarve Basin, which is the offshore continuation of the Southern Fringe:

- *The Porto/Galicia Basin* extends westwards offshore towards the continental margin. It occupies an area of about 2150 km^2 down to the 200 m water depth contour and about 2800 km^2 down to 1000 m water depth. It contains up to about 8 km of Late Triassic to Late Cretaceous sedimentary rocks. Five deep wells have been drilled.

- *The Lusitanian Basin* lies to the south of the Porto-Galicia basin and is the largest of the Portuguese basins; it continues from the onshore to the offshore and has a total area of about 22,000 km^2 with a maximum sedimentary thickness of some 6 km. Age of sediment fill is similar to that of the Porto-Galicia basin but thickness of the Jurassic sediments relative to the Cretaceous is generally more important than in the Porto-Galicia basin. 53 wells >500 m deep have been drilled onshore and offshore in the Western Fringes/Lusitanian Basin.

- *The Alentejo Basin* is small (some 2,600 km^2), developed only in the offshore, mostly in waters deeper than 200 m, and has never been drilled. Judging from seismic and outcrop data, it contains a significant thickness of sediments of both Mesozoic and Cenozoic age.

- *The Algarve Basin* (about 8,500 km^2) lies in the extreme south of the country, on- and offshore, roughly parallel to the coastline; it continues to the east as the Spanish Cadiz basin, where the Gulf of Cadiz gas field occurs. Depth to the Carboniferous basement may exceed 7 km and the fill is of Late Triassic to Recent age. The relative thickness of the Cenozoic and, particularly, the Neogene sediments, is larger than in the western basins.

Reservoir rocks in the offshore sedimentary basins
The coarse, red clastics of Late Triassic age, which were the first strata deposited in the basins show fair to good reservoir characteristics at outcrop along the rims of the Lusitanian, Alentejo and Algarve basins. Their grain size and porosity generally decrease, however, towards the basins' axes and in the few wells that penetrated these clastics they were found to be, at best, mediocre reservoirs. Better reservoir development may be, perhaps, locally present in distributary river channels cutting

through the basins. The overlying Hettangian evaporitic sequence provides ample sealing to any Upper Triassic reservoirs.

The first carbonates deposited over the evaporitic section; limestones and dolomitic limestones of Sinemurian age, include some thin vuggy and fractured intervals with fair reservoir properties.
No other reservoirs are known in the Lower and Middle Jurassic sections except perhaps for the Algarve basin in which Middle Jurassic vuggy dolomites and limestones with porosities up to 11% were observed in wells and may present better development elsewhere.

Fair to good reservoirs are found locally in the Upper Jurassic of the Lusitanian basin both as Oxfordian reefal carbonates and Kimmeridgian to Portlandian coastal clastics. The presence of similarly aged reefal build-up reservoirs is assumed in the Porto Basin.

The Lower Cretaceous, mainly terrestrial friable sands and conglomerates which occur over most of the Lusitanian basin with a more or less constant thickness of some 300-400 m and porosities of up to 35% constitute an excellent reservoir. Seals for these sands could be provided by interbedded shale and/or by the overlying Cenomanian marls and marly limestones.

No significant reservoirs are known in the Cenozoic section in the Porto and Lusitanian Basins. However, in the Algarve Basin, good Miocene sand reservoirs with average porosities of up to 35% were drilled in several wells. Sandy limestones of the same age also possess fair reservoir properties with up to 15% average porosity.

Summary
The only significant reservoir rocks for CO_2 storage offshore Portugal are likely to be the Lower Cretaceous sands and conglomerates in all basins, and Miocene sand reservoirs in the Algarve Basin. No maps showing their depth and detailed distribution are available so it has been assumed that one reservoir horizon occurs in each basin and this covers 50% of the basin area.

B.7 Deep saline aquifers in Finland

The storage potential for Finland has recently been evaluated under the National Programme on Technology and Climate Change (Koljonen et al. 2002). The outcome of the study was discouraging and concluded that no suitable geological storage sites exist in Finland. The nearest potential storage sites are offshore oil and gas fields in the North Sea and the Barents Sea.

B.8 Deep saline aquifers in Sweden

The country is geologically dominated by crystalline bedrocks terrains and deep saline aquifer storage potential is thus restricted to southern Sweden (Ahlberg et al. 1986). The Mesozoic sediments in this part of Sweden were deposited in fault bounded basins at the Fennoscandian border zone. The position of the potential storage sites in a structurally complex geological setting poses extra challenges to trap definition and integrity of cap rocks. Structurally defined traps are likely to be the main storage target.

A description of deep saline aquifers with potential for CO_2 storage in Skåne (southernmost Sweden) and offshore areas (southern Botnian Sea) is given in an open file report (Ericson et al. 1997). According to Mikael Erlström (Pers. Com. 2003, Geologial Survey of Sweden, Lund) no studies on the potential for geological storage of CO_2 have been undertaken in Sweden since the 1997 study (Ericson 1997). Related studies on the potential for geothermal energy systems, however, are in progress and may give valuable information on the reservoir properties of the deep saline aquifers. Recent geothermal studies in the Malmö–Copenhagen area includes drilling of new wells with target in sandstones of Triassic and Jurassic age.

Erlström (Appendix 1 in Ericson 1997) presented a summary of data from ten sandstone deep saline aquifers with potential for CO_2 storage in southern Sweden. Several of these, however, do not meet the depth criteria of 800–900 metres, which is considered minimum for storage of CO_2 in a dense phase. The sandstone aquifers meeting the GESTCO depth criteria are listed in Table A.1.

Table A.1 Deep saline sandstone aquifers with storage potential in south-western Sweden (based on Ericson (1997).

Deep saline aquifer	Thickness (m)	Depth (m)	Area (km^2)	Capacity	Comment
Arnagergrönsand	30–80	1000–1500	10 000	>70 Mtonnes	Based on 2% storage efficiency
Upper Cretaceous-Lower Jurassic (undiff.)	150–250	1400–1500	1000–5000	Not estimated	Varied lithologies and reservoir properties
Kågeröd sandstone	80–120	1600–1800	1500	Not estimated	Varied lithologies and reservoir properties
Buntsandsten and Ljunghusensandsten	150–200	2000–2200	200	Not estimated	Varied lithologies and reservoir properties. Some intervals with excellent reservoir properties

Ericson (1997) presented a preliminary calculation of the storage potential related to the most widespread of the deep saline aquifers; Arnagergrönsanden. Assuming an aquifer thickness of 50 m and 25% porosity the minimum storage capacity within Swedish borders was 70 Mtonnes (2% sweep efficiency) and maximum 3.5 Gtonnes (100% sweep efficiency).

Mappping of deep saline aquifers in the southern Botnian Sea suggest that deep saline aquifers with potential for CO_2 storage is present in the southeastern part (Appendix 2 in Ericson 1997). In this part of the Botnian Sea the Middle Cambrian Deimena sandstone is situated between 800 and 2000 m depth. A number of structural closures were mapped although the major part are situated in Polish and Lithuanian waters and thereby outside the Swedish interest area. The storage potential of the Deimena sandstone within the Swedish offshore area was not calculated in Ericson (1997).

C Review of additional hydrocarbon field data

C.1 Oil and gas fields in Austria

The oil and gas fields of Austria are described in detail in 'Erdol und Erdgas in Osterreich' (OMV 1993). The vast majority of these fields are relatively small, the largest being Matzen, which was discovered in 1949. Matzen has expected total production of 77 million tonnes of oil and 38 billion m^3 gas and a corresponding estimated maximum CO_2 storage capacity of 89 million tonnes. Only seven fields have estimated maximum CO_2 storage capacities of more than 10 million tonnes.

The oil and gas fields are found in the Molasse basin and the Vienna Basin. Total production from Austria to date of 104 million tonnes of oil and 69 billion m^3 gas.

C.2 Oil and gas fields in Ireland

There are no onshore oil or gas fields in Ireland. Offshore gas fields are found in the North Celtic Sea Basin, off the south coast. Additionally, there is a single gas field, Corrib, in the Slyne Basin, off the west coast of County Mayo.

The main field in the North Celtic Sea Basin is Kinsale Head. It has 2 satellites, Ballycotton and SW Kinsale, tied back to the main Kinsale Head Platform. There are several other smaller sub-commercial discoveries in the North Celtic Sea Basin, but these are not likely to be of interest from a CO_2 storage perspective. Kinsale Head has Ultimately Recoverable Reserves of $42.28 * 10^9$ m^3 and an estimated maximum CO_2 storage capacity of $185 * 10^6$ tonnes.

The Corrib field is in the early stages of development. It has estimated Ultimately Recoverable Reserves of $24 * 10^9$ m^3 gas and an estimated maximum CO_2 storage capacity of $68 * 10^6$ tonnes.

C.3 Oil and gas fields in Italy

C.3.1 Oil fields

Matavelli & Novelli (1990) identify six main oil fields in Italy: Villafortuna, Rospo, Gela, Ragusa, Vega and Nilde. The most significant by far are those in the Vega Basin in Sicily. Additionally there has been significant condensate production from the (onshore) Malossa gas field in the Po Basin.

The onshore part of the Vega Basin in Sicily contains the Gela and Ragusa fields and the much smaller Mila, Perla, and Ponte Dirillo fields. Gela and Ragusa had each produced about $20 * 10^6$ m^3 oil up to 1992 (Barbier 1996). The ultimate recovery of Mila is estimated at $2.2 * 10^6$ m^3, and that of Perla at $1.1 * 10^6$ m^3 (Schramm & Livraga 1986). Ponte Dirillo has produced over $2 * 10^6$ m^3 oil to date. The offshore Vega field has ultimately recoverable reserves estimated to be in the order of $64 * 10^6$ m^3 (Schramm & Livraga 1986).

The most significant offshore producer in the Adriatic is Rospo Mare, with an ultimate recovery of about 15 * 10^6 m^3 (Andre & Doulcet 1991).

C.3.2 Gas fields

The main gas fields of Italy are concentrated in the Po Basin onshore and offshore, and the Pedeappenninic Basin its continuation offshore in the Adriatic Sea - the Apulian Platform. They include Cortemaggiore, Malossa, Gagliano, Candela, Caviaga, San Salvo-Cupello, Selva-Minerbio, Porto Corsini Terra, and Dosso degli Angeli (onshore), and Luna, Porto Corsini Mare, Amelia, Agostino-Porto Garibaldi and Barbara offshore. The exceptions are Luna (off the south coast) and Gagliano in Sicily.

C.4 Oil and gas fields in Portugal

According to the web site of the Geological and Mining Institute of Portugal: http://www.igm.pt/departam/npep/history.htm, there are no oil and gas fields in Portugal.

Quoting from this web site:

"Although a significant amount of exploration work has been carried out so far in the Portuguese sedimentary basins, even the Lusitanian basin, the most explored one, with a drilling density of only 2.4 wildcats per 1,000 km^2 must still be considered under explored. Results were often encouraging, and there is no question about the presence - at least in some of the basins - of all the necessary ingredients (mature source rocks, sealed reservoirs, traps) for potential economic accumulations. However, these ingredients have not yet been found in the right combination and no commercial production has yet been achieved."

C.5 Oil and gas fields in Spain

A good summary of the oil and gas fields of Spain and the prospects for further hydrocarbon discoveries is given by Melendez-Hevia & Alvarez de Buergo (1996). Gas occurs in the Guadalquivir and Ebro onshore basins and the Gulf of Cadiz (the offshore continuation of the Guadalquivir Basin). Both oil and gas occur in the offshore Gulf of Valencia Basin.

Guadalquivir Basin offshore (Gulf of Cadiz)
Several discoveries have been made to date. The first were in the Gulf of Cadiz and in the 1970's were grouped together as the Atlantida fields, with a total combined reserve of 250 BCF. However, their dispersed nature results in them being subcommercial and they have not yet been developed.

Guadalquivir basin onshore
Despite the shallow nature of this basin, several discoveries have been made. Marismas (30 BCF of reserves) is in production. Las Barreras (4.5 BCF, El Romeral (4.5 BCF) and El Ruedo (5 BCF) are all under appraisal.

Ebro Basin (onshore)
There has been a significant discovery in the Ebro Basin; the Serrablo gas field. The reserves have been estimated to be about 90 BCF but after significant production this field has now become a gas storage facility so it is not available for CO_2 storage.

Gulf of Valencia (offshore)
The Gulf of Valencia is located offshore, between the east coast of Spain and the Balearic Isles. It contains subcommercial and commercial oil discoveries, the latter tied back to and exploited from the Casablanca field. The commercial fields include Casablanca 126 x 10^6 bbls to 1995), Tarraco (14.4 * 10^6 bbls, depleted), Dorada (16.6 * 10^6 bbls depleted) and Amposta (56 * 10^6 bbls, depleted).

C.6 Oil and gas fields in Switzerland

There is only one gas field in Switzerland; Finsterwald. This had reserves of between 80 and 180 * 10^6 m^3. Production started in 1985 and the field is now depleted. There are no oil fields in Switzerland.

D Review of additional deep unminable coal seam data

In addition to the inventory of deep unminable coal seams in the GESTCO project, data for several more countries have been gathered.

D.1 Deep unminable coal seams in Austria

As far as could be determined, there are no active underground coal mines in Austria unless any of the underground mines in the Salzburg area are still open.. However, there is some opencast lignite mining. There is not considered to be any quantifiable potential for CO_2 storage by sorption onto coal because, as far as could be determined, there are no significant bituminous coal deposits in Austria at depths suitable for CO_2 storage.

D.2 Deep unminable coal seams in Ireland

It is thought that no underground coal mining is currently taking place in Ireland. Historically there has been very minor production from Carboniferous (mainly Namurian and Dinantian) coal seams in Eire and some minor production from the Westphalian Coal Measures in Northern Ireland (UK). The main coalfield in Eire was the Connaught or Arigna coalfield, in counties Sligo, Leitrim and Roscommon. This occupies the high ground around Lough Allen. Both opencast and underground mining took place. The five coals mined were bituminous and the best seam (the Main coal, average 0.46 m thick), is exhausted. In 1980 it was thought that small reserves were available in the Middle Crow seam (6 million tonnes) and another 9 million tonnes might be available east of Lough Allen (Sevastopulo 1981). The field is too shallow to have any coal-bed methane, ECBM or CO_2 storage potential.

The Leinster or Kilkenny coalfield is structurally a shallow basin. It has been mined since the beginning of the eighteenth century. The coal was of good quality and anthracite rank. The thicker seams are exhausted and only small quantities were being produced in 1980 (Sevastopulo 1981). Production is now thought to have ceased. Because the field is shallow and the rank is too high for successful coal-bed methane production, this coalfield is thought to have no CO_2 storage potential.

The Northern Ireland coalfields are all small, exhausted and no longer mined. They are not considered to have significant CO_2 storage potential.

D.3 Deep unminable coal seams in Italy

The main coal deposits of Italy are located in two broad areas. Anthracite deposits, which are generally small and have complex geological structure, are found in the Alps and Sardinia. Cainozoic lignites and sub-bituminous coals are also found in the Apennines and Sardinia, and Mesozoic bituminous coals are found in a few scattered deposits in the same areas (IEA 1983).

D.3.1 Mainland Italy

The mainland Italian coal mining industry is small and all of the coal production is opencast. The IEA Coal Research: 'Concise Guide to World Coalfields' (1983) states that there are no significant coalfields in Italy (i.e. coalfields producing more than 1 million tonnes of coal per year), and there are no large active underground coal mines. At Valdarno on the western slopes of the Apennines north of Rome, many small pockets of lignite occur. Only very localised mining has been carried out, e.g. at Santa Barbara in Tuscany. The Italian lignites are of no interest for coal-bed methane production or CO_2 storage.

D.3.2 Sardinia

The Sulcis coalfield in Sardinia contains >1000 million tonnes of sub-bituminous coal. A coal-bed methane exploration licence has recently been granted in this coalfield, operated by Kimberley Oil NL of Australia in a joint venture with Heritage Petroleum. The permit covers an area of 615.2 km^2, almost the whole of the Sulcis Basin. The coal-bearing formation, the Produttivo Formation, is up to about 150 m thick and contains up to 13 coal seams with cumulative coal thickness of 35-40 m. In the drilled area of the basin coal seams are proved to depths of 730 m. The best prospects for methane are likely to be in the western parts of the basin.

There is active underground mining in the Seruci and Neraxi Figus mines in the Monte Sinni mining concession area to the northwest of Carbonia. Note that significant amounts of methane have not been recorded in these mines. In the mining area the Produttivo is abut 40-50 m thick and occurs at depths of 200-400 m (Dreesen et al. 1997). Depth and thickness increase to the SSW.

Potential for CO_2 storage by sorption onto coal

If there is successful coal-bed methane production in the Sulcis coal basin, there may be potential there for CO_2 storage as part of an ECBM project. However the low rank, very high volatile matter and lack of significant methane in the mines suggest low prospectivity. Furthermore, coal has not been proved at depths >800 m so the coalfield currently falls outside the criteria used for CO_2 storage by adsorption onto coal in this study.

D.4 Deep unminable coal seams in Portugal

The main coal deposits of Portugal consist of a Palaeozoic anthracite deposit at Sao Pedro da Cova and Pejao in the north west of the country, a Mesozoic semi-anthracite deposit at Cabo Mondego and Cainozoic lignite deposits between Lisbon and Coimbra (IEA 1983).

At Sao Pedro da Cova the seams are thin and geologically disturbed. In 1983, production was from a number of small mines. At Pejao there are larger resources but smaller production. There are two workable seams, which are steeply inclined (IEA 1983).

The lignite deposits may be typified by the Rio Maior deposit, which, in 1983 was being mined by surface methods (IEA 1983).

The semi-anthractie was being mined at Cabo Mondego in 1983 (IEA 1983) but this coalfield may now be closed (see below).

Coal mining

There are not thought to be any large active underground coal mines in Portugal. The IEA Coal Research Concise Guide to World Coalfields (1983) confirms that there are no significant coalfields in Portugal (i.e. coalfields producing more than 1 million tonnes of coal per year). The last coal mine is thought to have closed in 1997.

Potential for CO_2 storage by sorption onto coal

There is not considered to be any potential for CO_2 storage by sorption onto coal because, as far as could be determined, there are no significant coal deposits in Portugal at depths suitable for CO_2 storage. There is definitely no potential for CBM production in Portugal (M. J. Lemos de Sousa, *personal communication*) and thus no potential for ECBM production.

D.5 Deep unminable coal seams in Spain

Underground coal mining

In 1992, over 95% of Spanish production came from three coalfield regions; the Asturias/Leon coalfields in the Cantabrian Mountains of northern Spain, the Andorra/Teruel coalfield between Tarragona and Valencia and the lignite fields of La Coruna in northwest Spain.

The Asturias/Leon region lies in the Cantabrian Mountains of northern Spain. The coal-bearing strata are of Carboniferous (Westphalian and Stephanian) age. It is structurally complex, with steeply dipping seams and severe folding and faulting and is subdivided into a number of small separate coalfields. Coal rank ranges from medium to low volatile bituminous to anthracite. The seams commonly contain high and variable ash contents and inclusions of quartzitic material (Daniel & Jamieson 1992).

In 1992 the recoverable reserves were estimated to be 1350 million tonnes and 1989 output was 12.7 million tonnes (Daniel & Jamieson 1992). Consequently current recoverable reserves are estimated to be in the order of 1220 million tonnes. The coalfield is exploited largely from underground mines.

Some of the coalfields in the region may have some potential for coal-bed methane production see below and Lemos de Sousa & Pinheiro (1996).

The Andorra/Teruel coalfield is of Lower Cretaceous age. Seams are of no higher than sub-bituminous rank. Deposition occurred in a series of separate blocks bounded by faults. This resulted in the production of a number of separate coal deposits. Contemporaneous tectonic activity caused block tilting so seam inclinations can be steep (Daniel & Jamieson 1992).

In 1992 the recoverable reserves were 225 million tonnes and 1989 output was 3.9 million tonnes (Daniel & Jamieson 1992). Consequently, current recoverable reserves are estimated to be in the order of 185 million tonnes. In 1992 there were 2 underground and 2 surface mines. The worked seams vary from 4 to 14 m in thickness and inclinations vary from 30° to near vertical.

The Teruel coalfield was the site of a European UCG trial.

The La Coruna coalfield in northwest Spain consists of two isolated Miocene lignite deposits at Puentes and Meirama. The remaining recoverable reserves were said to have a very short life in 1992 and may have been exhausted by now. In 1992 there were 2 surface mines feeding output directly into adjacent electricity generating plants. In 1992 the working depth was around 150 m and final depth was anticipated to be 320 m. These coalfields have no potential for CO_2 storage

Potential for CO_2 storage by sorption onto coal

The Asturias/Leon coalfield region contains very steeply dipping, commonly faulted coal seams. Even in 1986 60% of the largest companies' production came from seams less than 1.5 m thick. Given that a large part of the coal production is uneconomic (Daniel & Jamieson 1992), much of the remaining reserve may eventually be available for CO_2 storage if it is at great enough depths. However, the number of seams, cumulative coal seam thickness, seam permeability and gas content in the individual coalfields, never mind the region as a whole, are not available for the study. Based on information in Lemos de Sousa & Pinheiro (1996), it is clear that the number and thickness of seams is highly variable, even within a single coalfield. Furthermore the depth to which coal seams occur is not known in many of the coalfields.

A preliminary investigation into the coal-bed methane potential of Spain (Lemos de Sousa & Pinheiro 1996) demonstrates that the only realistic prospects for CBM in Spain are in the Asturias/Leon region. The relevant coalfields are, in decreasing order of importance, the Cinera-Matallana, Cerredo-Villablino (considered to have equal potential), La Pernia-Barruelo, southern part of the Central Asturian coalfield and El Bierzo. Unfortunately there is insufficient information available to make a realistic calculation of the coal-bed methane potential of these coalfields and consequently insufficient information available to estimate their CO_2 storage potential.

D.6 Deep unminable coal seams in Switzerland

As far as could be determined, there are no active underground coal mines in Switzerland. Significant coal production ended after active mining in the First and Second World Wars. There is not considered to be any potential for CO_2 storage by sorption onto coal because, as far as could be determined, there are no significant coal deposits in Switzerland at depths suitable for CO_2 storage.

E Discussion note on storage capacity calculations and input data

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This draft note was used for starting up the discussion with colleague researchers in Canada, USA and Australia. In addition, we propose at the end of this memo the levels of data detail that could preferably be analysed in the present project (CCC-EUR): the minimum level of detail is level D0; level D1 is applicable to the hydrocarbon occurrences. Incidentally higher levels of data detail can be reached, which can be used to check the results of capacity calculations at a lower level.

Considered storage options

- Deep saline aquifers
- Hydrocarbon fields
- EOR
- ECBM

E.1 Levels of data detail

Several levels of data detail have been determined with increasing accuracy but decreasing areal representativity:

D0: Only extent of sedimentary basins with potential deep saline aquifers known
D1: Ultimate Recoverable resources at the level of hydrocarbon provinces and plays from e.g. the USGS assessments
D2: Volumetric storage capacity - Pore volume data: Net to Gross, porosity, and geometrical data: reservoir dimensions, sweep efficiency, or storage efficiency (extra parameters for coals?)
D3: Effective storage capacity includes reservoir dynamics D2 and reservoir engineering data (#wells, leak-off pressure, reservoir pressure, fluid properties e.g. viscosity)
D4: Reservoir engineering case study (not part of CCC-EUR project)

E.2 Modelling approaches depending on the level of available data

E.2.1 Deep saline aquifer trap

Data level D0

Volumes for CO_2 storage potential in deep saline aquifers are difficult to estimate, as already indicated by Hendriks (1994). Little volumetric information on deep saline aquifers is known, since they have very limited economical value (contrary to for example fresh water aquifers).

However many sedimentary basins, although poorly mapped, contain deep saline aquifers. Based on the extent of the sedimentary basin, a rough estimation can be made of the aquifer storage potential.
Single values for the storage capacity at the D0 level are not really valuable, the only value is in calculated probability distributions (or min, median, max values) accounting for the large uncertainties.

Data required:
- Horizontal/areal extent of sedimentary basin (m^2)

Data assumed:
- Range of aquifer thickness (50 – 300 m)
- Range of aquifer porosity (5-30 %)
- Percentage of traps in area (1%)
- Storage efficiency (percentage of trap that can be filled; 2%)

CO_2 = area × aquifer thickness × (PT/100) × (SE/100) × (porosity / 100) × density CO_2

With:

CO_2	=	volume of CO_2 that can potentially be sequestered (kg)
Area	=	surface area of sedimentary basins (m^2)
Aquifer thickness	=	thickness of aquifer (m)
PT	=	traps in area (%)
SE	=	storage efficiency (%)
Porosity	=	porosity of the rock (%)
density CO_2	=	density CO_2 at supercritical conditions (kg/m^3)

Data level D1

The calculation method for data level D1 is similar to that of D0. The difference is in the availability of data, e.g. limited regional seismic surveys and drilling have been carried out which allows the determination of the thickness of the deep saline aquifer and the percentage of traps in area.

Data required:
- extent of aquifer (m^2)
- extent of seals (m^2)
- range of aquifer thickness (50 – 300 m)
- percentage of traps in area (1-4%)

Data assumed:
- range of aquifer porosity (5-30 %)
- percentage of trap that can be filled (2-6 %)

Data level D2

In data level D2 more information is known about the deep saline aquifer, e.g. because of an extensive seismic survey and the availability of wells that penetrated the deep saline aquifer.

We assume that CO_2 storage is restricted to a trap. For an open deep saline aquifer the volume of storage is then depending on the size of the trap rather than the size of the deep saline aquifer. For a closed deep saline aquifer however one should take into account the volume that is available by compression only. The theoretical storage capacity based on the pore volume available for CO_2 is given by

$$V_{CO2}^{(0)res} = V^{trap} \varphi NG(1 - S_{wr})\rho_{CO2}^{res}$$

To obtain a more realistic estimate for the volume available for CO_2 storage the pore space should be corrected by the sweep efficiency factor f_{se}. Defining the storage volume of the trap

$$TV_{CO2} = V^{trap} \varphi NG(1 - S_{wr}) f_{se}$$

then for an open deep saline aquifer the more accurate estimated CO_2 storage amount is given by

$$V_{CO2}^{(1)res} = TV_{CO2}^{res} \rho_{CO2}^{res}$$

If the deep saline aquifer is closed the storage volume can not exceed the volume CV_{CO2} that can be achieved by compression. This volume is calculated using the total compressibility cw+cf and the maximal allowable pressure drop pmax -pres:

$$CV_{CO2} = (c_w + c_f) V^{res} \varphi NG(1 - S_{wr})(p_{\max} - p_{res})$$

The CO_2 storage volume $V_{CO2}^{(1)res}$ is then given by

$$V_{CO2}^{(1)res} = \min\{TV_{CO2}^{res}, CV_{CO2}^{res}\}\rho_{CO2}^{res}$$

Data required:
- Trap volume
- Porosity
- N/G ratio
- Residual water saturation
- Maximum injection pressure (LOP)
- Definition of aquifer: open or closed

Data assumed:
- Sweep efficiency
- Rock/fluid compressibility

Data level D3

Assuming that the injection time T and the number N of wells are given the maximal injection rate q_{max} can be calculated. The injection rate q_{max} is the injection rate such that the increasing wellbore pressure at the end of the injection period reaches the

maximal allowable injection pressure e.g. the leakoff pressure. The rate q_{max} can be estimated Using an analytic expression of the injectivity index that relates the pressure drawdown and the injection rate together with a mass balance equation.
In case of an open reservoir the pressure at the reservoir boundary is equal to the reservoir pressure and remains constant during injection. The altering pressure at a no-flow reservoir boundary, however, is not known. The pressure drawdown in the reservoir is then better expressed in terms of the average pressure $\overline{p}$. The pressure drawdown in a cylindrical reservoir and a single fully penetrating well at the symmetry axis is given by:

$$p_w - \overline{p} = \frac{q\mu}{2\pi k_h h}\left\{\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right\} = \frac{q}{J}, \quad [1]$$

where J is called the injectivity index. The average reservoir pressure $\overline{p}$ can be calculated from the material balance (taking injection rate q positive)

$$cAh\varphi(\overline{p} - p_{res}) = qt \qquad [2]$$

The wellbore pressure pw = pw(t) can be calculated from the equations [1] and [2].

To account for well interference we further assume that each well has a volume of influence. For simplicity, we take a cylindrical volume of influence equal for each well.
When CO_2 is injected into an deep saline aquifer or an abandoned hydrocarbon reservoir a growing zone around the well exists with different mobility than the replaced fluid. To account for the two-mobility zones the pressure equations in the two zones are coupled.
The CO_2 compressibility is mainly pressure dependent for temperatures above 60 °C while the CO_2 viscosity is mainly temperature dependent and, to a much lesser extent, pressure dependent. In the model we have approximated these parameters by pressure and temperature depending functions. The adjusted two-phase mass balance equation is of the same form as for Equation [2] where the compressibility coefficient c is replaced by saturation weighted fluid compressibility.

Data required:
- Reservoir radius
- External radius of aquifer (pressure communication)
- Thickness reservoir
- Surface area (A)
- Porosity
- Horizontal permeability
- Injection time
- Number of wells
- Well bore radius
- Viscosity
- Compressibility
- Maximum injection pressure (LOP)
- Confining pressure/depth
- Temperature

Data assumed:
- Not applicable

E.2.2 Gross aquifer

Considerable debate is going on with regard to the calculation of the storage capacity of deep saline aquifers (sometimes referred to with the term hydrodynamic trapping) Several approaches are available that stress one particular aspect of aquifer injection other then injection in traps.

Mechanical approach starting from the compressibility of matrix and fluids (Van der Meer's 2% rule assuming an overpressure of about 10 MPa (Novem report, 1996)
Solubility approach: 50 to 60 kg/1,000 kg water at pressures higher than 100 bar and temperature larger than 30 ^{o}C equivalent with a storage efficiency of free gas of 7% (Joule II; Mike Celia, Princeton University). However there is considerable dispute about the kinematics of CO_2 dissolution on the field scale.
Gas saturation approach (Obdam, personal communication; enormous uncertainty in residual gas saturation). In the Novem study (1996a) the following is stated for open regional traps: 1 Mt/km^2 with an overpressure of about 10 MPa. The area, which is overpressured is much larger than the actual CO_2 storage area.

Hydrodynamic approach combining reservoir rock (vertical and hor. Permeability, thickness and length of aquifer) and fluid properties (physical properties of fluids) resulting in dimensions of free CO_2 gas body in a deep saline aquifer. This is not yet well explored.

Resuming, we advise to use a storage efficiency of 2% with a lower limit of 1% accounting for a lower maximum overpressure than 10 MPa and an upper limit in case a significant amount of CO_2 dissolves during the operational period.

Data level D0

Data required:
- Horizontal extent of sedimentary basin

Data level D1

Data required:
- extent of sedimentary basin
- extent of seals
- range of aquifer thickness (50 – 300 m)

Data assumed:
- Minimum thickness of 10 m
- Minimum depth of 800 m
- Minimum permeability of 50 mD

Data level D2

Data required:
- Aquifer volume
- Porosity
- N/G ratio

E.2.3 Abandoned gas reservoir

Data level D0

We assume that the lowest level of information D0 is not relevant for hydrocarbon reservoirs.

Data level D1 (Production data)

This concept is applicable to data from the USGS hydrocarbon inventory at the level of hydrocarbon provinces (D1a) and from the GESTCO database at the level of individual hydrocarbon fields (D1b).
We make a difference between a closed and an open reservoir with considerable water influx. The water production is neglected assuming that the gas fields are developed with a production strategy with minimal water production to avoid water treatment or re-injection costs.
For a closed gas reservoir a rough approximation for the storage capacity can be calculated using the gas recovery data converted to reservoir conditions:

$$V_{CO2}^{(0)res} = UR_{gas}^{st} B_g \rho_{CO2}^{res}$$

If the gas reservoir is an open system the storage capacity is then reduced by the amount of water influx:

$$V_{CO2}^{(0)res} = \left(UR_{gas}^{st} B_g - V_{waterinflux}^{res} \right) \rho_{CO2}^{res}$$

Data on the total volume of water influx shall most likely not be available. This will need expert knowledge or reservoir simulation.

Data required:
- Ultimate recovery
- Volume formation factor / depth
- Pressure
- temperature
- Water influx
- Definition of reservoir: open or closed

Data level D2 (volumetric geological data)

Similar approach as the aquifer storage option for this data level.

Data level D3

Similar approach as the aquifer storage option for this data level

E.2.4 Incremental oil production/Abandoned oil reservoir

Data level D0

We assume that the lowest level of information D0 is not relevant for hydrocarbon reservoirs.

Data level D1

For this data level we assume that no field-specific information is available, estimates are based on basin-wide information (e.g. from USGS data at the level of provinces).

The original oil in place (OOIP) is calculated from the Ultimate Recoverable Resources (URR):

OOIP = URR/((average API[18] gravity + 5)/100)

The part of oil $OOIP_C$ that will be in contact with CO_2 is:

$OOIP_C = OOIP \times C$

with $0.75 < C < 1$. The extra oil due to incremental oil production is then

$EOR = R_E \times OOIP_C = R_E \times C \times OOIP$

An empirical relation is derived (based on 7 EOR cases) between the R_E and the API gravity. The total volume of CO_2 that can be stored is calculated from the extra oil EOR and an empirical ratio R = (Net CO_2)/EOR [tonne/BO]. (Net CO_2 is the amount that is ultimately stored).

It is assumed that the incremental oil production can be divided in a part that requires high amount of CO_2 to recover it and a part that needs a low amount of CO_2 to be produced. Taking this into account one gets:

$\text{Net } CO_2 = f_{(high\ CO2)} \times EOR \times R_{(high\ CO2)} + f_{(low\ CO2)} \times EOR \times R_{(low\ CO2)}$

[18] API Gravity: An arbitrary scale expressing the gravity or density of liquid petroleum products, as established by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the compound. Light crude oils generally exceed 38 degrees API and heavy crude oils are commonly labelled as all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity

with $f_{(high\ (low)\ CO2)}$ the fraction of oil that needs high (low) amounts of CO_2 and $R_{(high\ (low)\ CO2)}$ the corresponding CO_2 needed to produce one BO of that "high(low) CO_2" oil. The fractions $f_{(high\ CO2)}$ and $f_{(low\ CO2)}$ are roughly estimated. The values depend on the depth and average API. The trend is that for $f_{(high\ CO2)}$ increases as API or depth increases.).

Data required:
- Distribution of expected OOIP of an individual field in a certain basin
- Distribution of API values of the oil in a certain basin
- Distribution of depth of the reservoir in a certain basin

Data assumed:
- Relation OOIP vs API
- Relation EOR vs API
- Contact factor
- Oil fractions

Data level D2 (volumetric production data)

The basic difference between level D1 and D2 is that the D2 level requires field specific production data (e.g. GESTCO data at the level of fields?).

For this storage type a first estimate for the storage capacity is the sum of the reservoir volume of the secondary oil recovery and tertiary oil recovery:

$$V_{CO2}^{(0)res} = \left(SR_{oil}^{st} + TR_{oil}^{st}\right)B_o \rho_{CO2}^{res}$$

Generally, information on the amount of secondary oil produced will be available if production data are known. To obtain a reliable estimate including the range of uncertainty of the volume of tertiary oil recovery expert knowledge or reservoir simulation is required.

Data required:
- Production data of primary, secondary and tertiary recovery.

Data level D3 (volumetric geological data)

An alternative capacity calculation is based on residual water and oil saturation

$$V_{CO2}^{(0)res} = V^{res}\varphi NG\left(1 - S_{wr} - S_{orc}\right)\rho_{CO2}^{res}$$

This expression is only based on a volumetric consideration, it does not take into account that CO2 only partly displaces the fluids. An improved estimate is obtained by introducing the sweep efficiency factor f_{se} to incorporate non-optimal displacement.

$$V_{CO2}^{(1)res} = V^{res}\varphi NG\left(1 - S_{wr} - S_{orc}\right)f_{se}\rho_{CO2}^{res}$$

Data required:
- Production data of primary, secondary and tertiary recovery.
- Residual water and oil saturation

Data level D4

Similar approach as the aquifer storage option for this data level.

E.2.5 ECBM

Data level D0

The problem with CO_2 storage in coal is that it is intended to be injected in deep unminable (depth circa > 1,000 m) coal seams. Generally, information (e.g. the cumulative thickness of the coal) is only available for the minable (circa < 1000 m) coal seams. The first major assumption at this data level is that the coal seams in the coal basins continue to a depth of at least 1500 m.

Data required:
- Extent of coal basin

Data assumed:
- Percentage of total area that can be used in the future (Conservatively, 10%).
- Cumulative thickness of the coal (1 – 100 m)
- Gas content
- Recovery factor
- Exchange ratio
- Coal density

The amount of producible CBM and the amount of storable CO_2 were estimated by the following calculation:

$$PG = 0.1 \times A \times TH \times \rho_{coal} \times GC \times RF$$

$$SCO_2 = PG \times ER \times \rho_{CO2}$$

With:

PG	=	producible gas [m^3]
SCO_2	=	storable CO_2 [kg]
A	=	surface area of coal basins [m^2]
TH	=	cumulative thickness of the coal [m] ρ_{coal} = coal density [t/m^3]
GC	=	gas content [$m^3{}_{STP}$ gas/t-coal]
RF	=	recovery factor [-]
ER	=	exchange ratio [-]
ρ_{CO2}	=	density of CO_2 at standard p, T conditions [= 1.977 kg/m^3]

Of course, this is a very rough calculation since it assumes homogeneous deposits throughout the investigated area.

The recovery factor is an estimation of the part of the gas-in-place that can be recovered. This depends among others on the completion of the separate coal seams and on the on the pressure drop that can be realised by pumping off large volumes of water. The production of CBM by conventional methods is often inefficient: normally only about 20% to 60% of the original GIP can be recovered. With gas injection the CBM recovery can be increased theoretically up to 100% [Stevens and Pekot, 1999].

The amount of CO_2 (in m^3) that can potentially be stored in the coal seams will be larger than the produced methane: based on experimental data from several authors [e.g. Puri and Yee, 1990; Stevenson et al., 1991; Hall et al., 1994] it is generally assumed that 2 molecules of CO_2 replace one molecule of CH_4. This ratio is called the Exchange Ratio. The adsorption capacity of coal for supercritical CO_2 ($P > 0.74$ MPa) is probably much higher, possibly up to 5:1 at 12 MPa [Hall et al., 1994; Krooss et al., 2002]. Based on the literature and on laboratory results, it is very likely that the adsorption capacity of coals, and therefore the ER, increases to some extent with increasing depth.

Data level D1

The calculation method for data level D1 is similar to that of D0. The difference is in the availability of data, especially geological data on coal thickness, depth and structural geometry.

Data required:
- Extent of coal basin
- Percentage of total area that can be used in the future (Conservatively, 10%).
- Cumulative thickness of the coal (1 – 100 m)

Data assumed:
- Gas content
- Recovery factor
- Exchange ratio
- Coal density
- (Coal permeability)

Note: with known depth, these factors could be made depth dependent

Data level D2

Data level 2 is limited to those areas with active (in past or present) Coal Bed Methane operations. In the calculation method data from laboratory experiments on the coal characteristics (moisture and ash content, gas content, rank of coalification), pressure and temperature effects, known recovery factors and possibly measured Exchange Ratios are taken into account. Also, a completion factor (indicating what percentage of the cumulative coal thickness can be completed) can be introduced.

Data level D3

Reservoir model (time factor)

E.3 Proposed levels of detail for the assemblage of cost curves

The overview presented in Table D. 1 can be used as a check for the needed information in the storage structure database (Chapter 2). The bottom line is that the lowest level of information provided should cover the whole of OECD Europe. For some options like the aquifer option, the aquifer-trap option or the ECBM option, this level might not reach the GESTCO 'standard', which means that in addition to the lower information level, one or two additional information levels for restricted areas (GESTCO study areas) in Europe could be added to check the outcomes of capacity calculations at a lower information level.

Table D. 1 Proposed levels of detail for cost analysis in present project (CCC_EUR).

Storage option	Information level/ geogr. coverage	Required data	Remarks
Deep saline aquifers	D0/ Europe	Horizontal extent of sedimentary basins	
	D1/ GESTCO+	Horizontal extent of aquifer	Test on D3 level
		Range of aquifer thickness	
		Aquifer porosity	
		Horizontal extent of seal	
Deep saline aquifer traps	D0/ Europe	See Aquifer - D0	
	D1/ GESTCO+	See Aquifer – D1	
		Percentage of aquifer traps	
	D2/ GESTCO	Trap volume	Test on D3 level
		Porosity	
		N/G-ratio	
Depleted gas fields	D1b/ Europe	Ultimate recovery	Alternatively D1a and D1b; testing on D2/D3 level[19]
		Depth (p, T)	
Incremental oil production	D1b/ Europe	Ultimate recovery/ Original Oil in Place	Two approaches; two sublevels of information: D1a and D1b; testing on D2/D3 level
		Depth (p, T)	
Depleted oil fields	D1b/ Europe	See incremental oil production	Alternatively D1a and D1b; testing on D2/D3 level
ECBM	D1/ Europe	Horizontal extent of coal basin	Comparable with D0
	D2/ GESTCO	See ECBM – D1	Comparable with D1; test on D3 level
		Cumulative thickness coal	
		Depth	
		Percentage of area that can be used	

[19] D1a starts from USGS inventory on the basis of hc provinces; D1b starts from individual hc reservoirs.

Notation

B_g :	Volume formation factor V^{res}/V^{st}
cf:	Rock compressibility [1/Pa]
cw:	Water compressibility [1/Pa]
CV_{CO2} :	Part of the volume in the aquifer that is available through compression [m^3]
fse:	Sweep efficiency factor [-]
NG:	Net to Gross [-]
pres:	Initial reservoir pressure [Pa]
pmax:	Maximal injection pressure (Leak off pressure) [Pa]
SR_{oil}^{st} :	Volume oil produced by secondary recovery (at standard conditions) [m^3]
SR_{oil}^{st} :	Volume oil produced by tertiary recovery (at standard conditions) [m^3]
Sw_r:	Irreducible water saturation [-]
Sorc:	Residual oil saturation after tertiary CO2 flooding [-]
TV_{CO2} :	Storage volume in the trap [m^3]
UR_{gas}^{st} :	Ultimate recovery of gas (at standard conditions) [m^3]
Vres:	Reservoir volume [m^3]
$V_{waterinflux}^{res}$:	Water influx volume (at reservoir conditions) [m^3]
$V_{CO2}^{(0)\,res}$:	0-th order appr. of CO2 storage capacity (at reservoir conditions) [kg]
$V_{CO2}^{(1)\,res}$:	1-st order appr. of CO2 storage capacity (at reservoir conditions) [kg]
ρ_{CO2}^{res} :	CO2 density at reservoir conditions [kg/m^3]
A:	area[m]
h:	average reservoir thickness[m]
PV:	pore volume[m^3]
p_w:	well bore pressure [Pa]
q:	injection rate [m^3/s]
r_e:	reservoir radius [m]
r_w:	wellbore radius [m]
t:	injection time [s]

F Input data for storage cost curves

The following tables show the main parameters that have been used in the calculation of the storage costs.
The yellow fields represent the data that have been used for the calculation of the costcurves.
The blue fields represent the data that have been used to define the distribution of the uncertainties, used for the Monte Carlo simulations. A triangular distribution has been taken for most probability distributions, except for the depth. In this case a uniform distribution was applied for the data from The Netherlands and from Norway. In the GESTCO database the depths of all reservoirs and aquifers in Norway and The Netherlands were arbitrarily set at 2000 m for onshore fields and at 3000 m for offshore data. Depth data were available for the other countries.
For the Monte Carlo analysis a uniform distribution between certain depth limits was taken into account for the uncertainty due to the lack of depth data for Norway and The Netherlands.

F.1 Data input for gas field storage concept

CUMULATIVE COST CURVE OF CARBONDIOXIDE STORAGE IN GASFIELDS
INPUT DATA

The following assumptions have been made for the calculations:
yellow and blue fields represent the the data that have been used for the calculations
blue fields indicate assumptions made for the Monte Carlo simulation

type of storage		gasfields onshore			gasfields offshore		
	units	mean	min	max	mean	min	max
Geological data							
reservoir depth	m	2000	1500	3000	3000	2500	3500
horizontal drilling	m	1000			1000		
reservoir thickness	m	125			125		
well capacity	Mt CO_2/yr	1,25	0,5	2	1,25	0,5	2
Economic data							
lifetime		20			20		
Discaount rate		10%			10%		
CAPEX							
Site development costs		1600000			1800000		
site investigation/exploration	euro						
site preparation							
mob/demob rig /platform							
engineering							
Env Imp Ass							
Drilling costs (per m.)	yr 2000	1750	1250	2250	2500	2000	3000
	yr 2020	1200	1000	1400	1750	1500	2000
Surface facilities		400000			25000000		
#wells/platform or location		6			6		
Monitoring investments		200000					
Monitoring equipment							
observation wells		.					
OPEX							
O&M&M rate		7%	5%	9%	8%	6%	10%
O&M		4%			5%		
monitoring costs		3%			3%		

F.2 Data input for oil field storage concept

CUMULATIVE COST CURVE OF CARBONDIOXIDE STORAGE IN OILFIELDS
INPUT DATA

The following assumptions have been made for the calculations:
yellow and blue fields represent the the data that have been used for the calculations
blue fields indicate assumptions made for the Monte Carlo simulation

type of storage		oil fields onshore			oil fields offshore		
	units	mean	min	max	mean	min	max
Geological data							
reservoir depth	m	2000	1500	3000	3000	2500	3500
horizontal drilling	m	1000			1000		
reservoir thickness	m	125			125		
well capacity	Mt CO2/yr	1	0,1	2	1	0,1	2
Economic data							
lifetime		20			20		
Discount rate		10%			10%		
CAPEX							
Site development costs		1600000			1800000		
site investigation/exploration	euro						
site preparation							
mob/demob rig /platform							
engineering							
Env Imp Ass							
Drilling costs (per m.)	yr 2000	1750	1250	2250	2500	2000	3000
	yr 2020	1200	1000	1400	1750	1500	2000
Surface facilities		500000			25000000		
#wells/platform or location		6			6		
Monitoring investments		4200000					
Monitoring equipment							
observation wells							
OPEX							
O&M&M rate		7%	5%	9%	8%	6%	10%
O&M		4%			5%		
monitoring costs		3%			3%		

F.3 Data input for incremental oil production

CUMULATIVE COST CURVE OF CARBONDIOXIDE STORAGE IN OILFIELDS WITH EOR
INPUT DATA

The following assumptions have been made for the calculations:
yellow and blue fields represent the the data that have been used for the calculations
blue fields indicate assumptions made for the Monte Carlo simulation

type of storage		EOR onshore			EOR offshore		
	units	calc	min	max	calc	min	max
Geological data							
reservoir depth	m	2000	1500	3000	3000	2500	3500
horizontal drilling	m	1000			1000		
reservoir thickness	m	125			125		
well capacity	Mt CO2/yr	0,1	0,05	0,2	0,1	0,05	0,2
Economic data							
lifetime		20			20		
Discount rate		10%			10%		
CAPEX							
Site development costs		1600000			1800000		
site investigation/exploration	euro						
site preparation							
mob/demob rig /platform							
engineering							
Env Imp Ass							
Drilling costs (per m.)	yr 2000	1750	1250	2250	2500	2000	3000
	yr 2020	1200	1000	1400	1750	1500	2000
Surface facilities		500000			25000000		
#wells/platform or location		6			6		
Monitoring investments		4200000			0		
monitoring equipment							
observation wells							
OPEX							
O&M&M rate		7%	5%	9%	8%	6%	10%
O&M		4%			5%		
monitoring costs		3%			3%		

F.4 Data input for deep saline aquifer storage concept

CUMULATIVE COST CURVE OF CARBONDIOXIDE STORAGE IN CONFINED AQUIFERS
INPUT DATA

The following assumptions have been made for the calculations:
yellow and blue fields represent the the data that have been used for the calculations
blue fields indicate assumptions made for the Monte Carlo simulation

type of storage		Aquifers onshore			Aquifers offshore		
	units	mean	min	max	mean	min	max
Geological data							
reservoir depth	m	2000	1500	3000	3000	2500	3500
horizontal drilling	m	1000			1000		
reservoir thickness	m	125			125		
well capacity	Mt CO2/yr	1	0,5	1,5	1	0,5	1,5
Economic data							
lifetime		20			20		
Discount rate		10%			10%		
CAPEX							
Site development costs		1600000			1800000		
Drilling costs (per m.)	yr 2000	1750	1250	2250	2500	2000	3000
	yr 2020	1200	1000	1400	1750	1500	2000
Surface facilities		400000			25000000		
#wells/platform or location		6			6		
Monitoring investments		2000000			0		
OPEX							
O&M&M rate		7%	5%	9%	8%	6%	10%
operations		4%			5%		
monitoring costs		3%			3%		

F.5 Data input for Coal Bed Methane production

CUMULATIVE COST CURVE OF CO2 STORAGE BY ECBM INPUT DATA				
The following assumptions have been made for the calculations:				
yellow and blue fields represent the the data that have been used for the calculations				
blue fields indicate assumptions made for the Monte Carlo simulation				
type of storage		**ECBM**		
	units	mean	min	max
Geological data				
reservoir depth	m	1000	800	1500
deviation	m	800		
reservoir thickness	m	200		
well ratio (producers/injectors		2,25		
well capacity	Mt CO2/yr	0,01		
Economic data				
lifetime		20		
Interest rate		10%		
CAPEX				
Site development costs		180000		
exploration&engineering	per project	1500000		
Env Imp Ass	per project	1500000		
Drilling costs (per m.)	yr 2000	500	400	600
	yr 2020	350	250	450
Surface facilities		400000		
# injectors/location		4		
Monitoring investments		2000000		
shallow observation wells				
observation wells				
OPEX				
O&M&M rate		8%	6%	10%
Operations&maintenance				
Monitoring costs				

Notes:
1. Site development costs relate to the actual drilling sites, which are to be numerous.
2. Exploration, engineering and Environmental Assessment are related to the whole project.

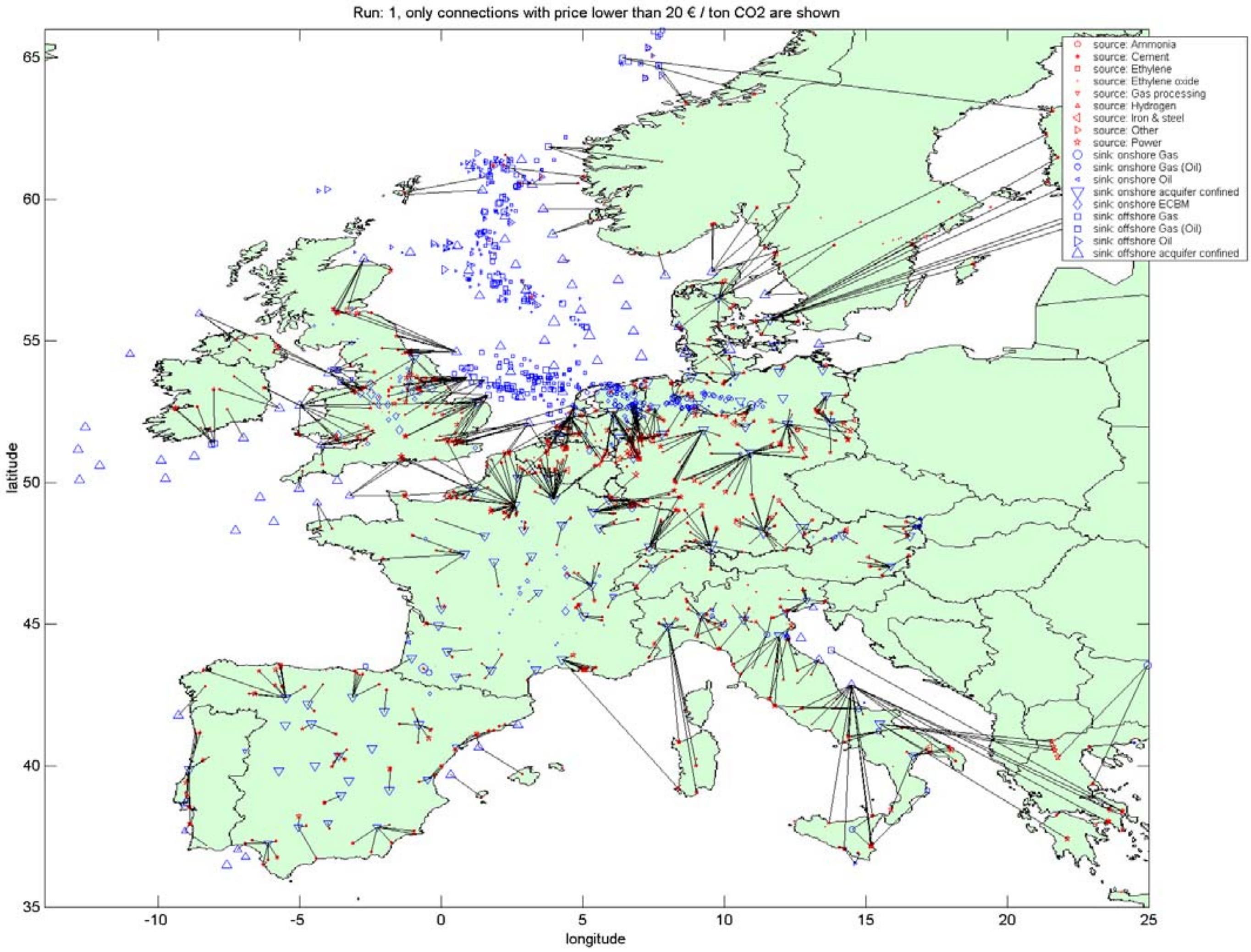
G Transport-storage implementation schemes and cost curves

G.1 All identified types of storage structures ex oil production (A)

Confined deep saline aquifers, oil fields without incremental oil production, gas fields and deep unminable coal seams both off- and onshore

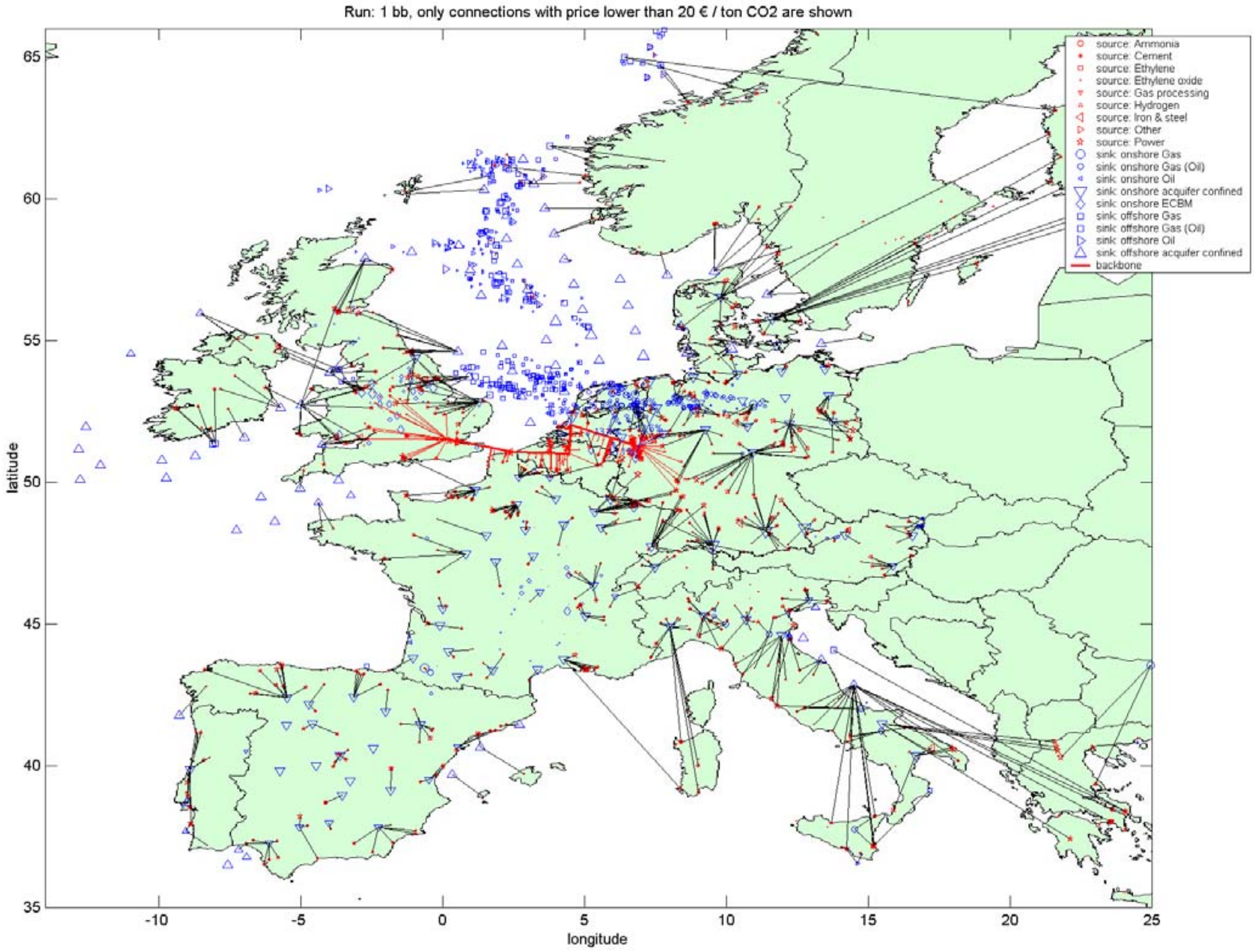
G.1.1 1-1 Implementation scheme A (A 1-1- 2000)

Map with sources, storage structures and transport infrastructure for scheme A 1-1



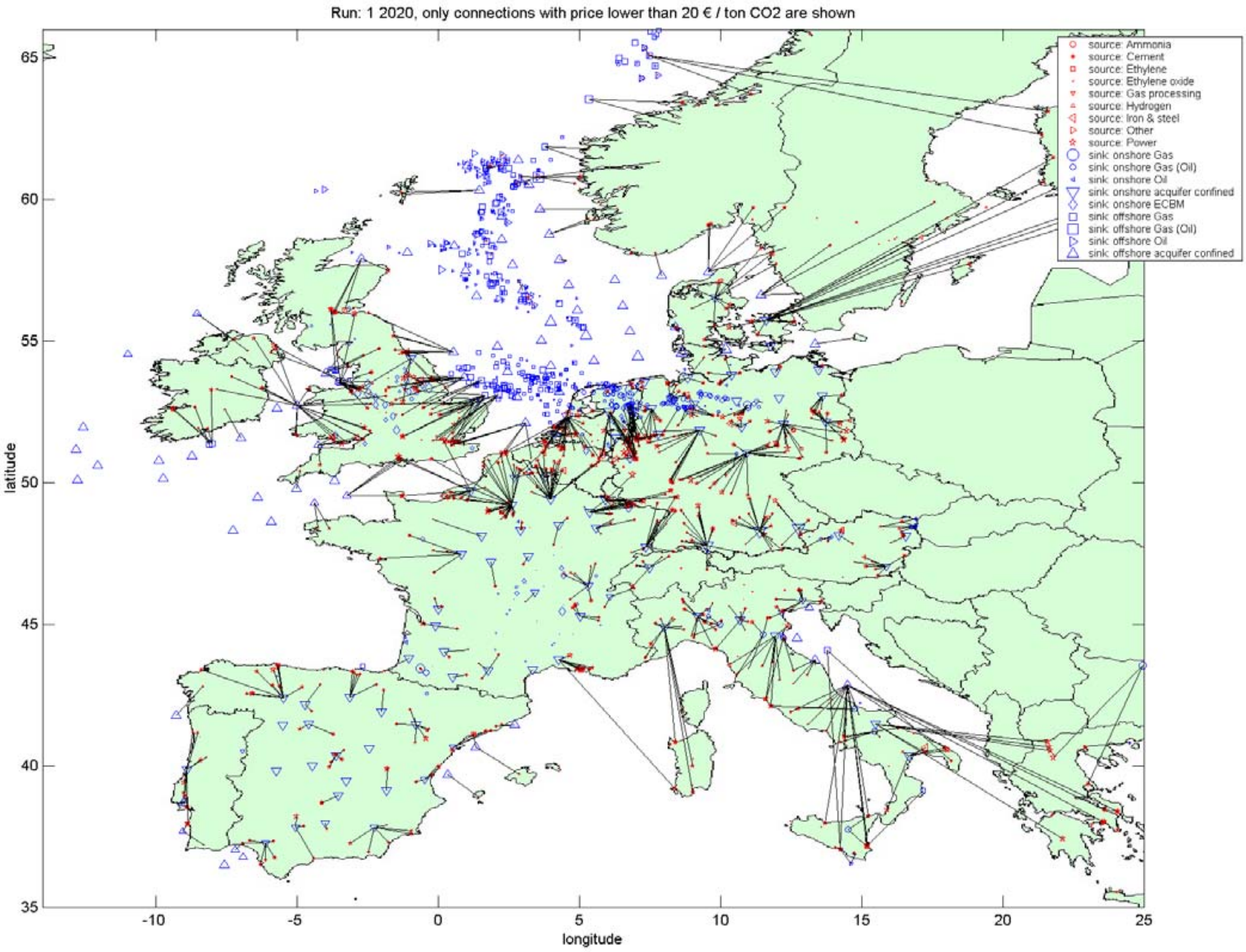
G.1.2 Implementation scheme A (2000 -backbone)

Map with sources, storage structures and transport infrastructure for scheme A bb

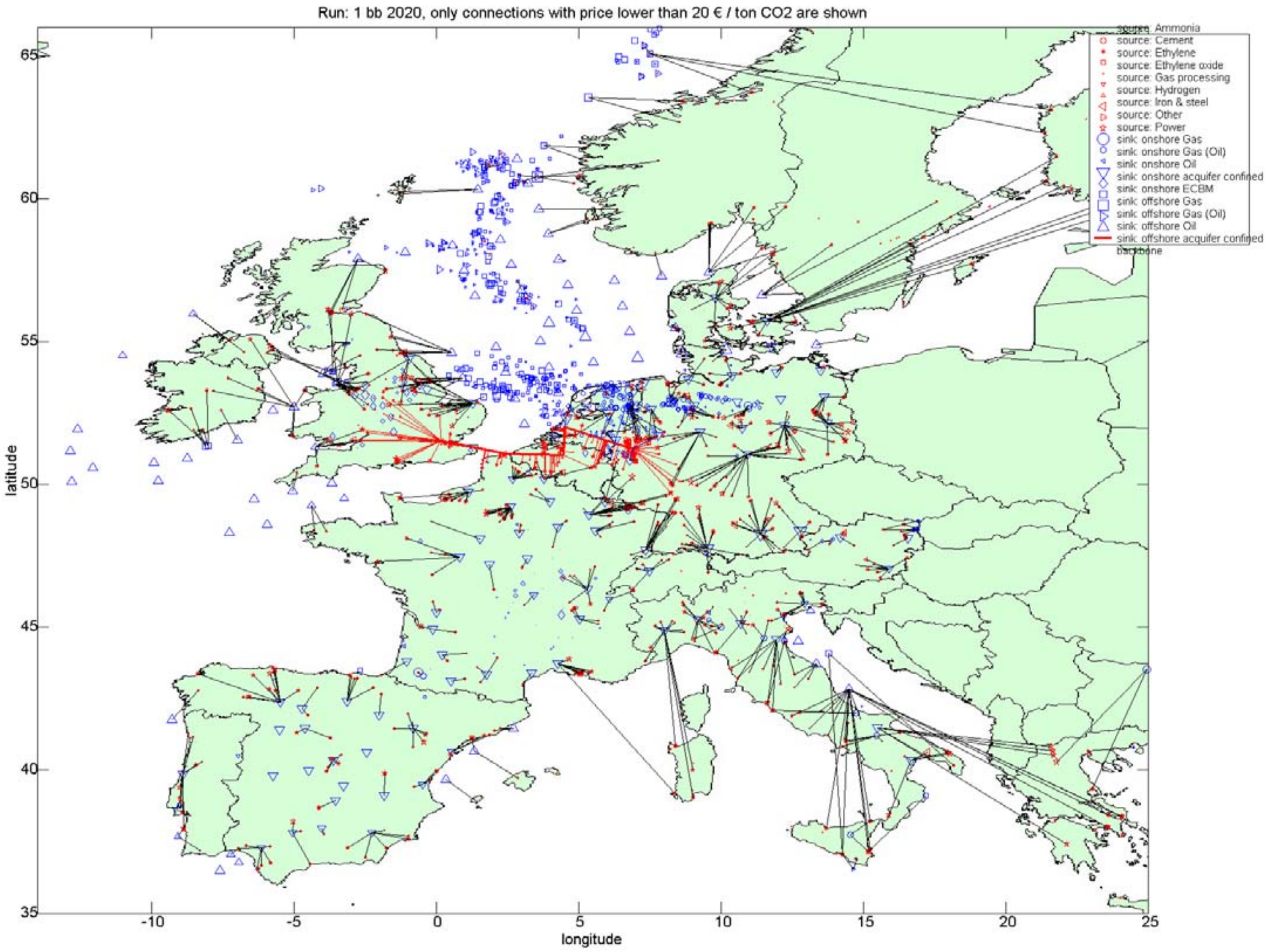


G.1.3 1-1 Implementation scheme A (A 1-1 - 2020)

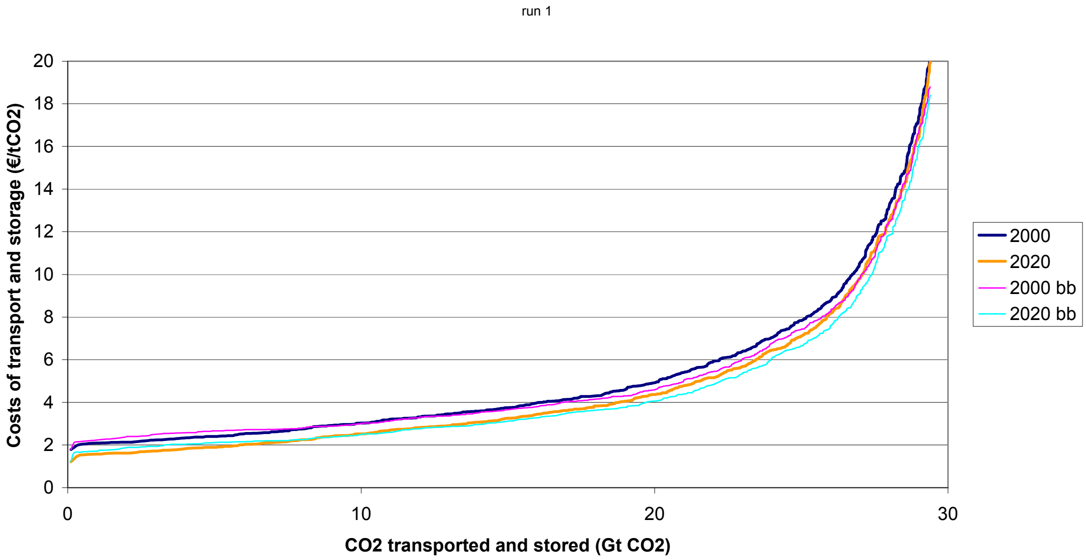
Map with sources, storage structures and transport infrastructure for scheme A 1-1



G.1.4 Implementation scheme A (2020 -backbone)



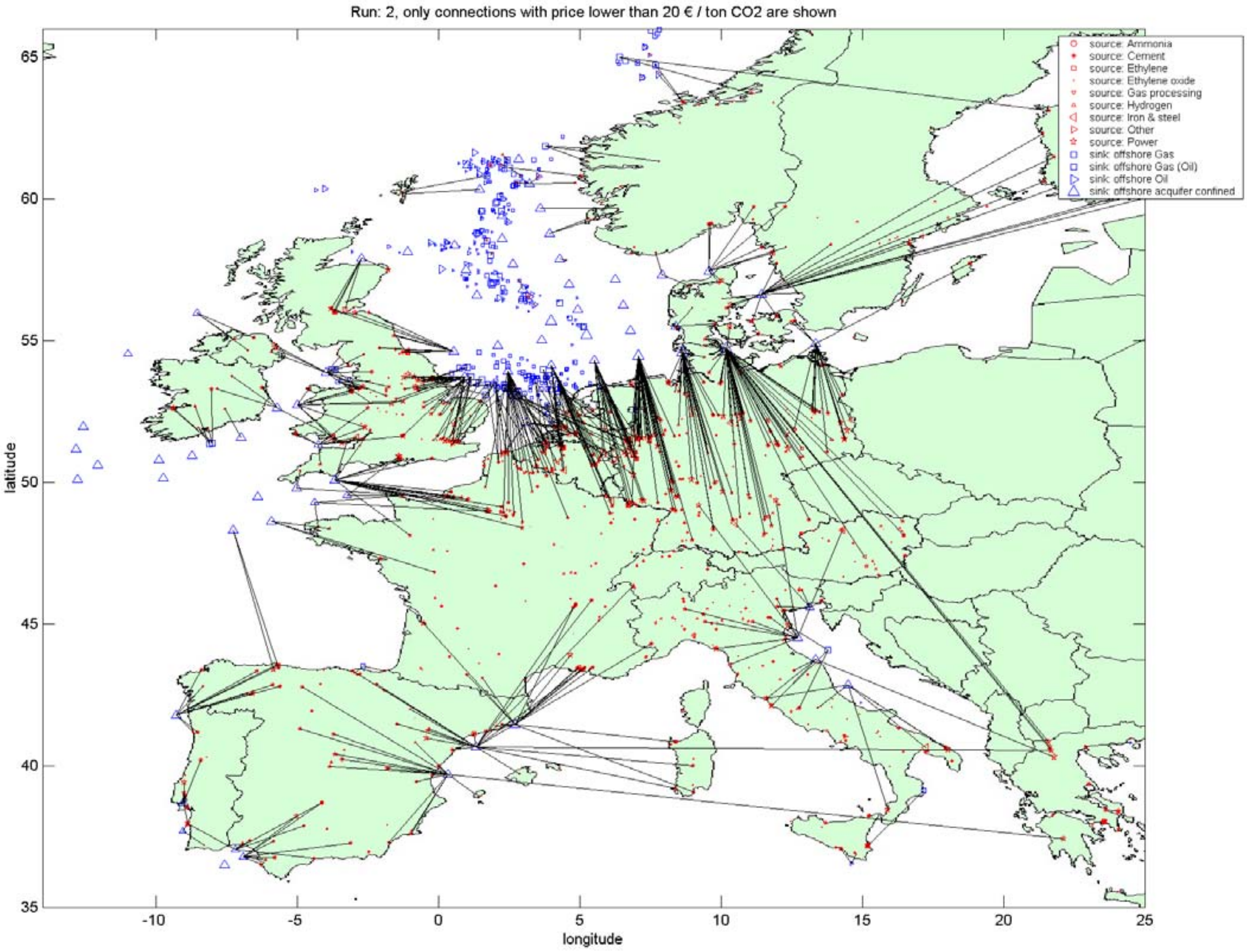
G.1.5 Cost curves for scheme A



G.2 All identified types of storage structures ex oil production offshore (B)

Confined deep saline aquifers, oil fields without incremental oil production, gas fields and deep unminable coal seams only offshore

G.2.1 1-1 Implementation scheme B (B 1-1 - 2000)



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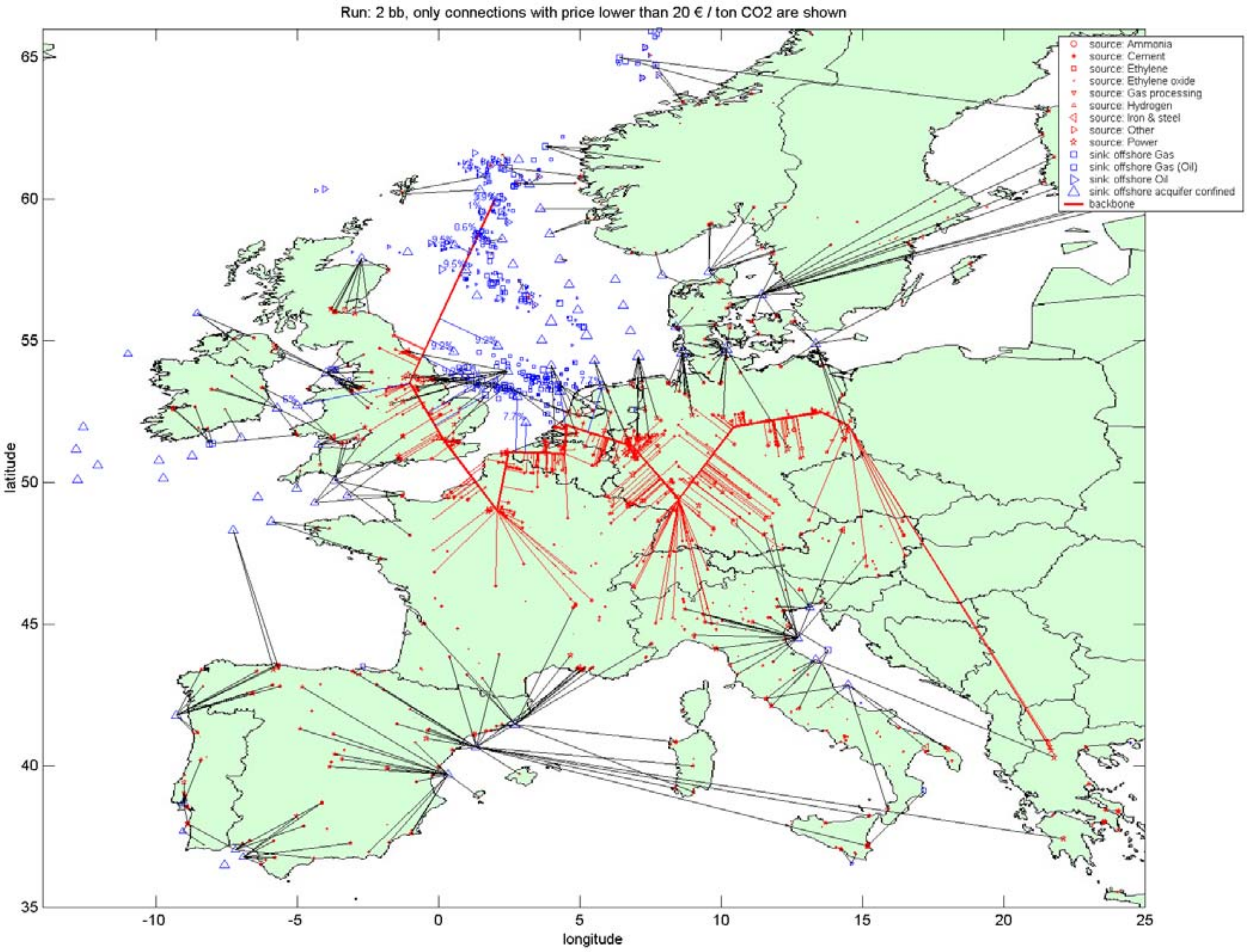
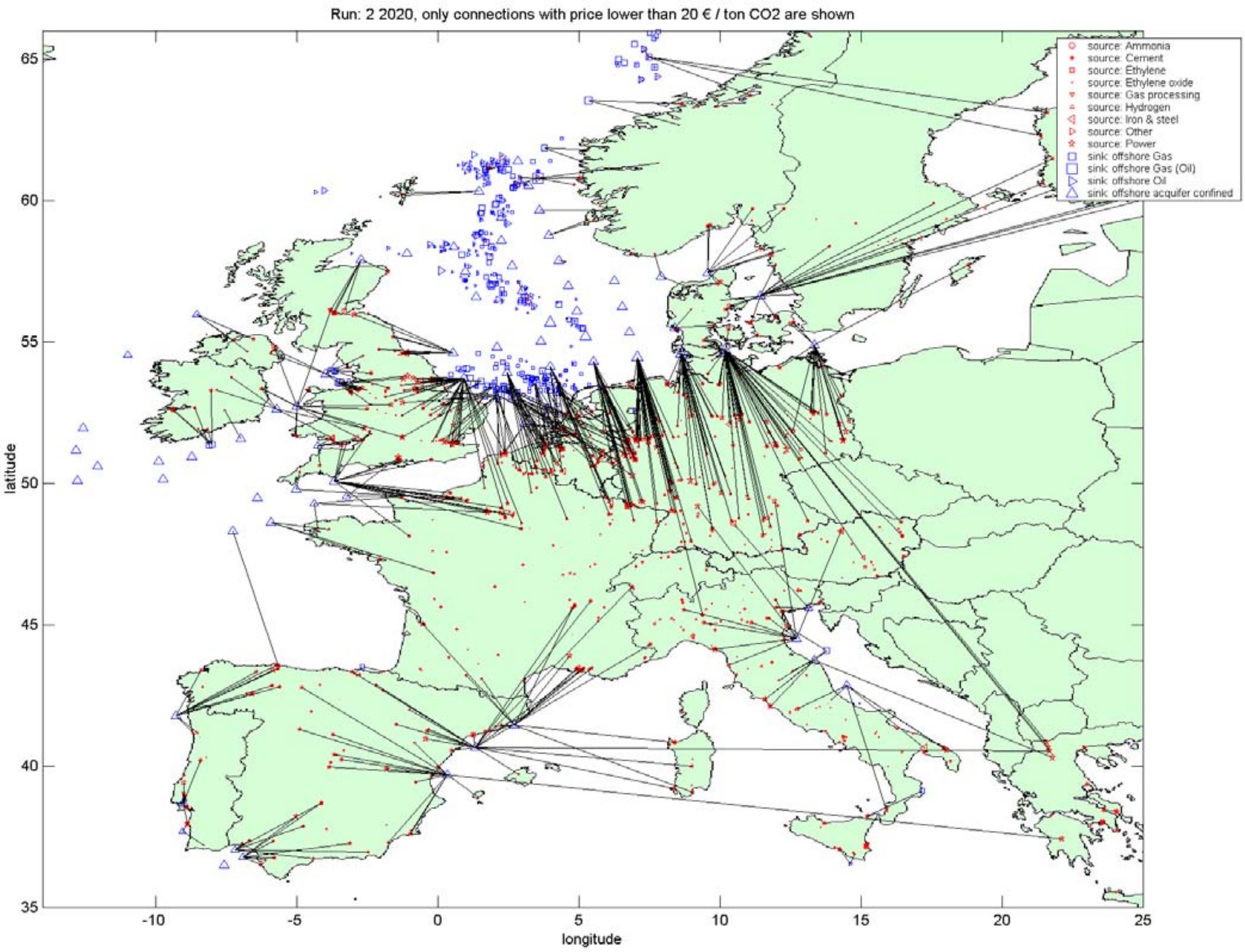


G.2.3 1-1 Implementation scheme B (B 1-1 - 2020)



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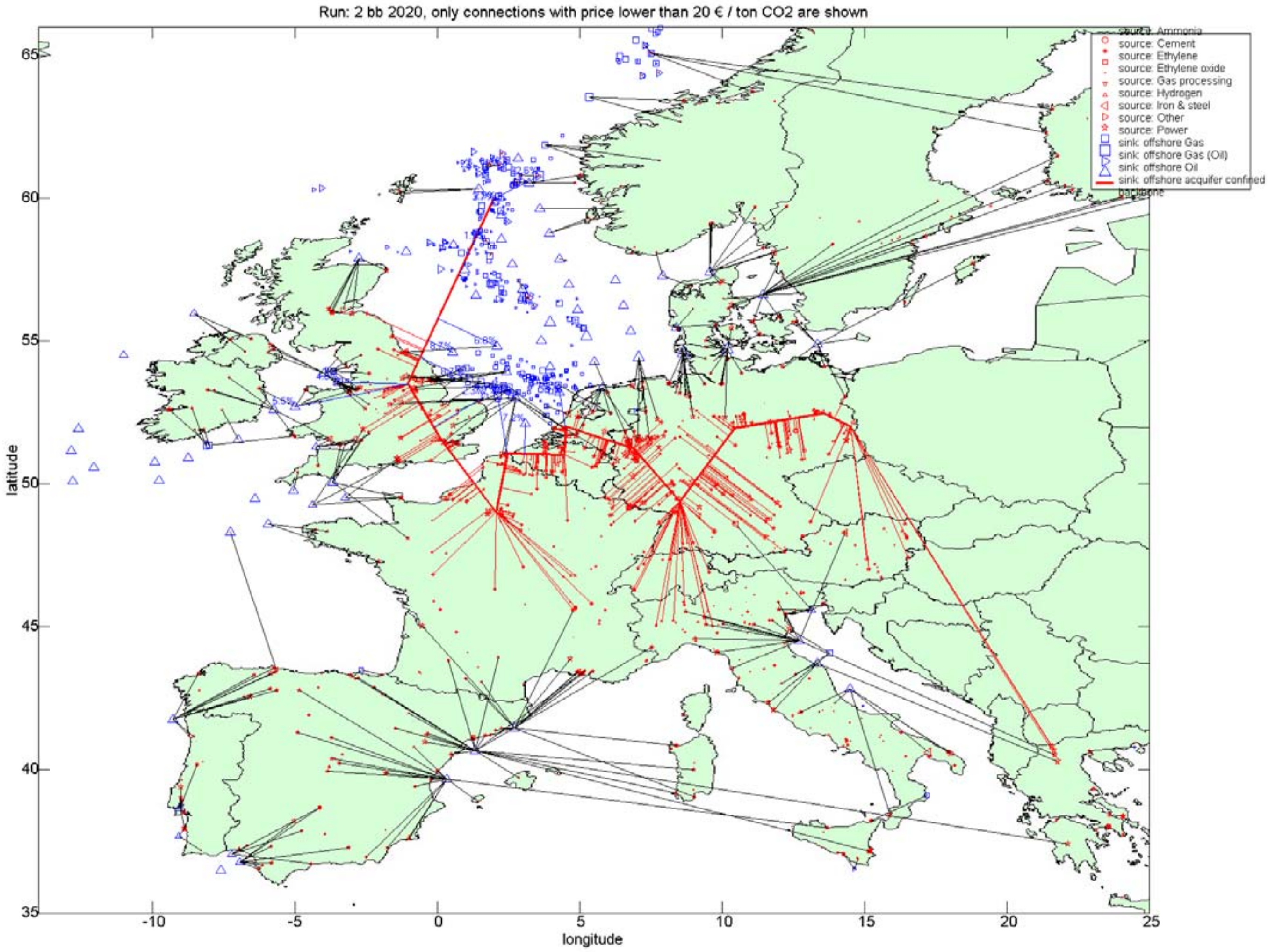
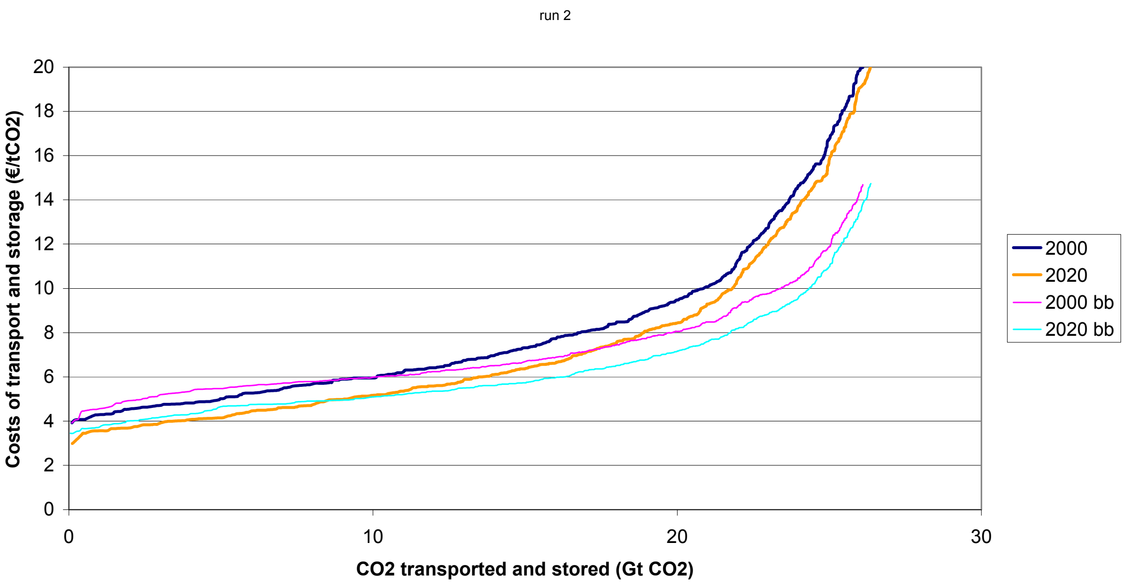


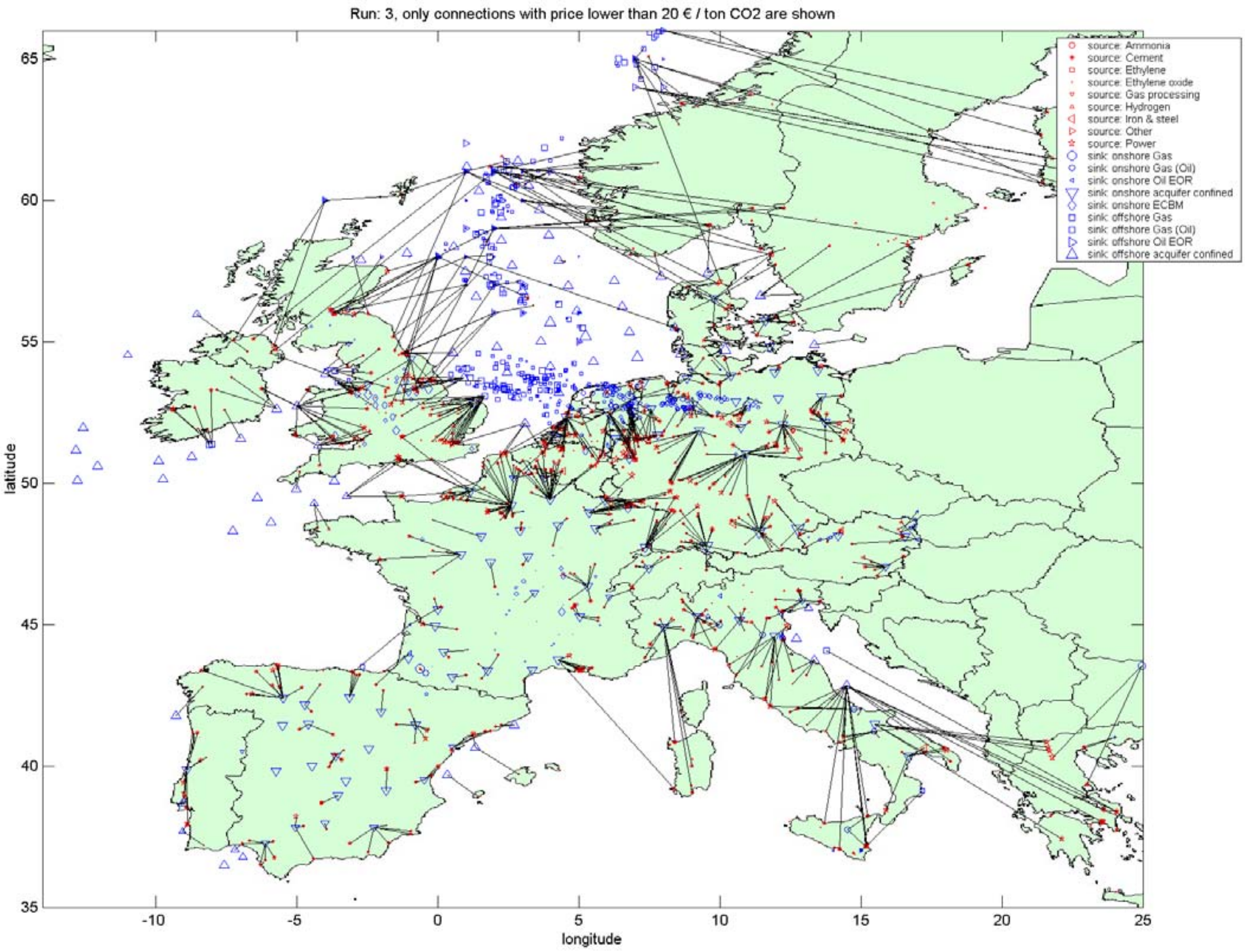
G.2.5 Cost curves scheme B



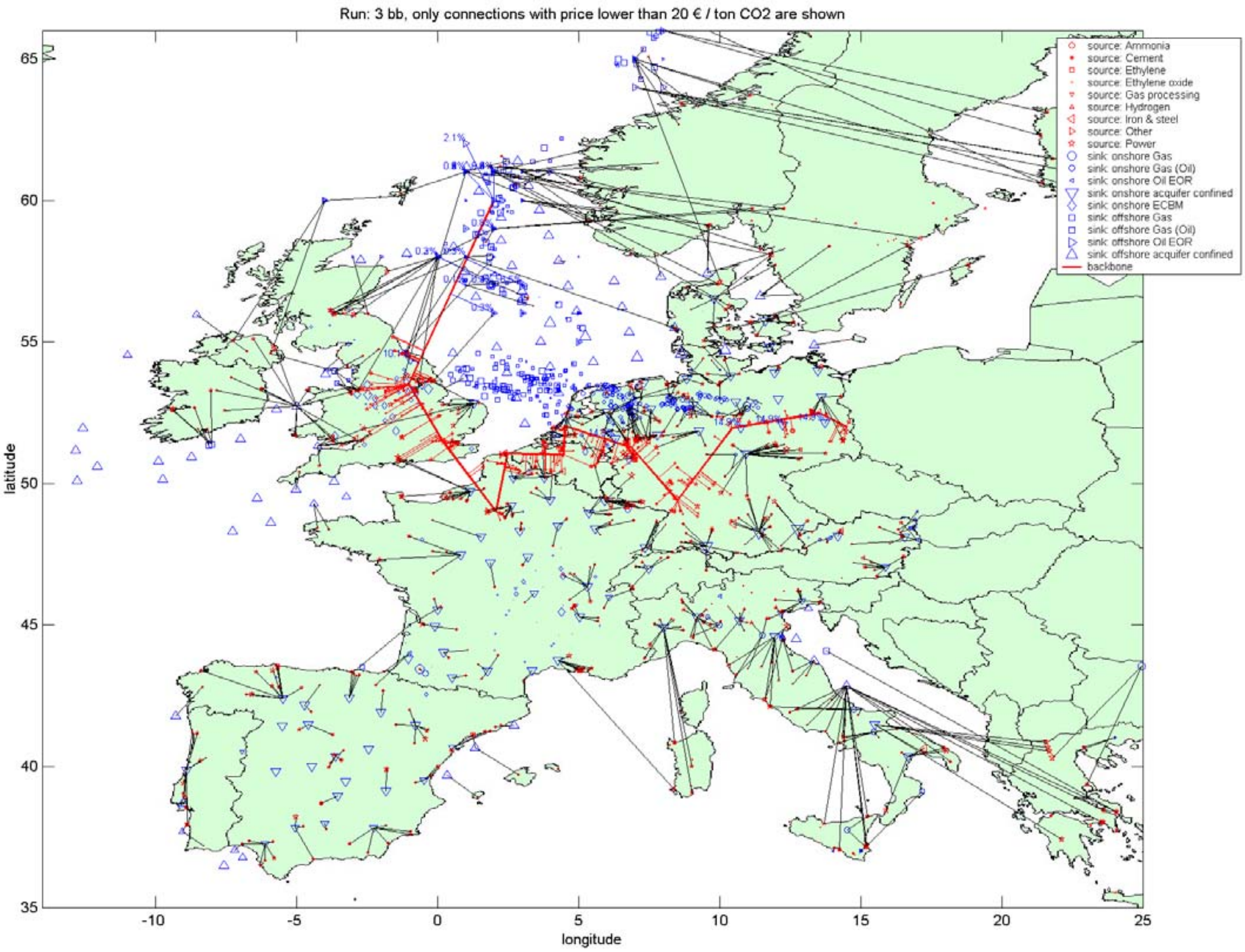
G.3 All identified types of storage structures including oil production offshore (C)

Confined deep saline aquifers, oil fields with incremental oil production, gas fields and deep unminable coal seams both on- and offshore

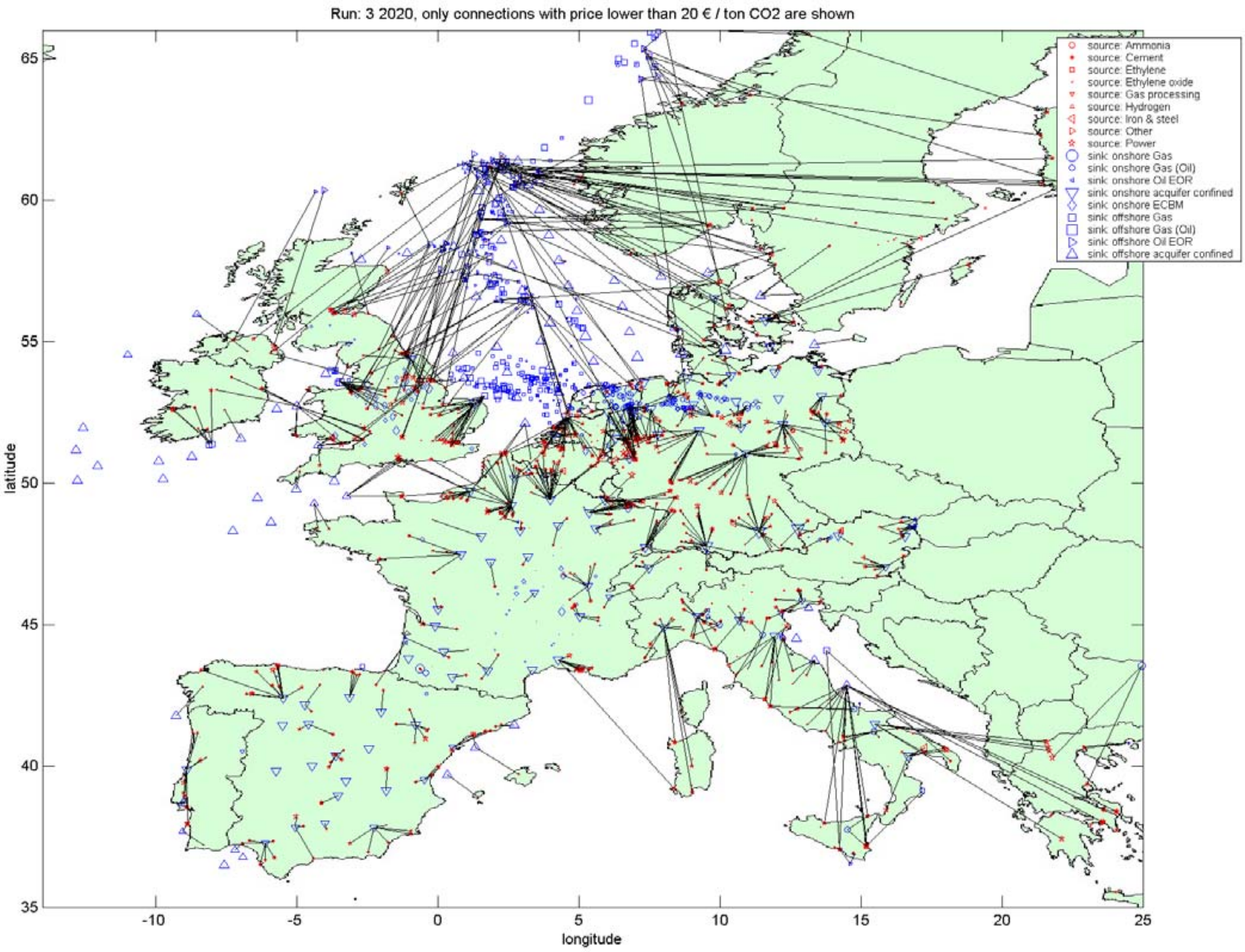
G.3.1 1-1 Implementation scheme C (B 1-1 - 2000)



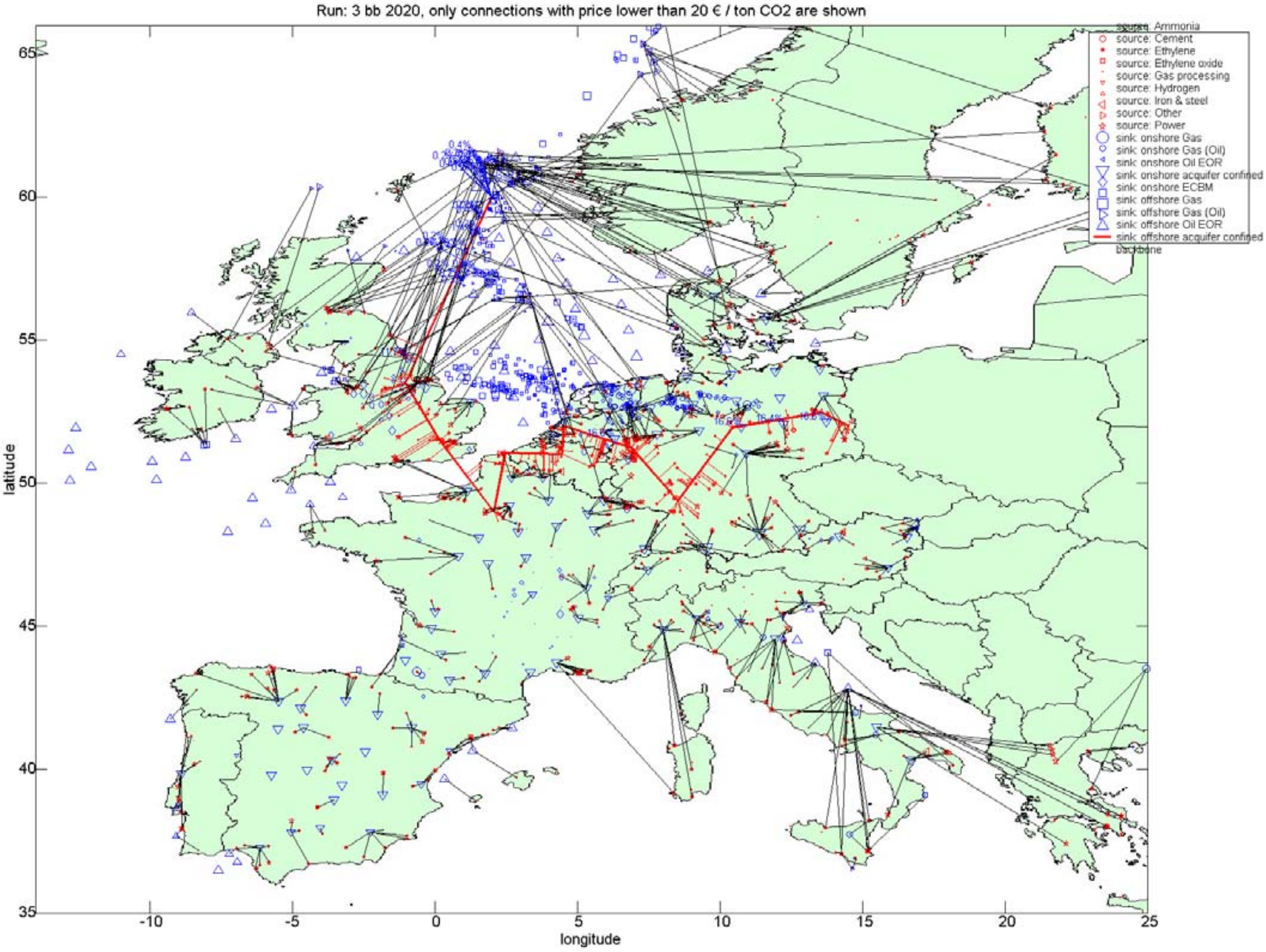
G.3.2 Backbone Implementation scheme C (B bb - 2000)



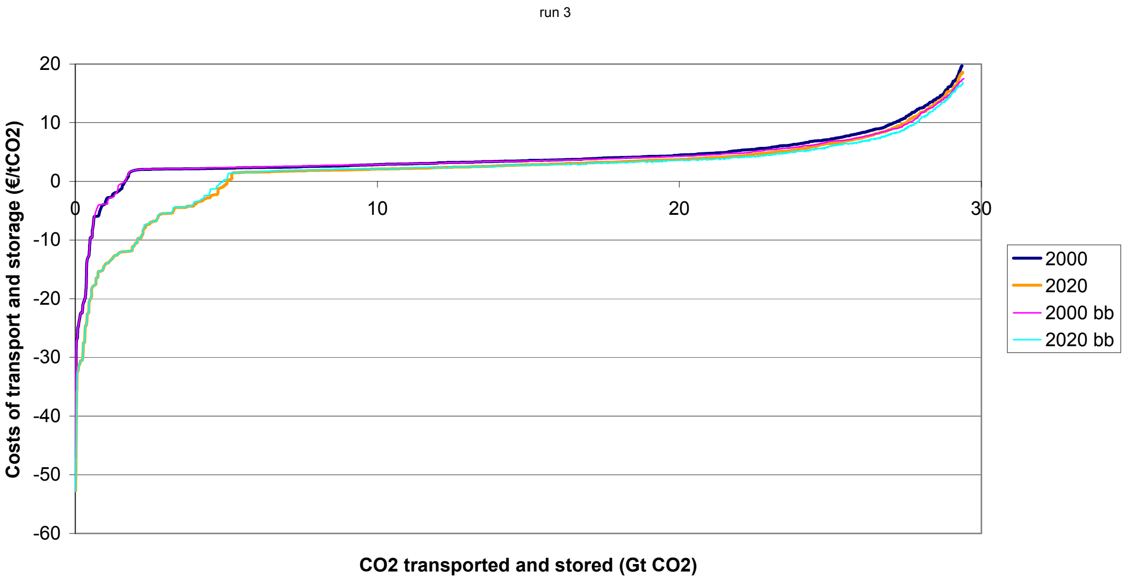
G.3.3 1-1 Implementation scheme C (B 1-1 - 2020)



G.3.4 Backbone Implementation scheme C (B bb - 2020)



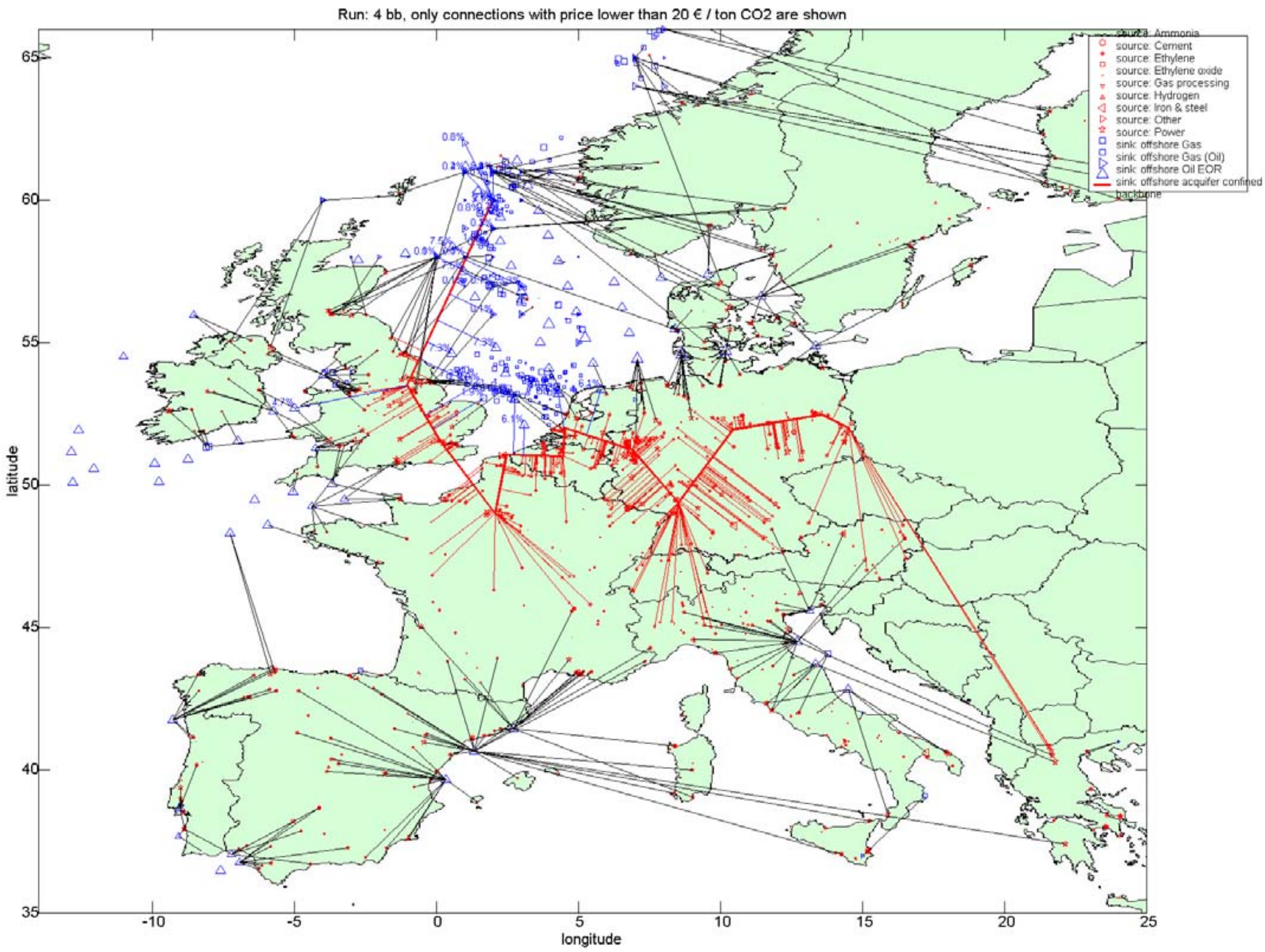
G.3.5 Cost curves scheme C



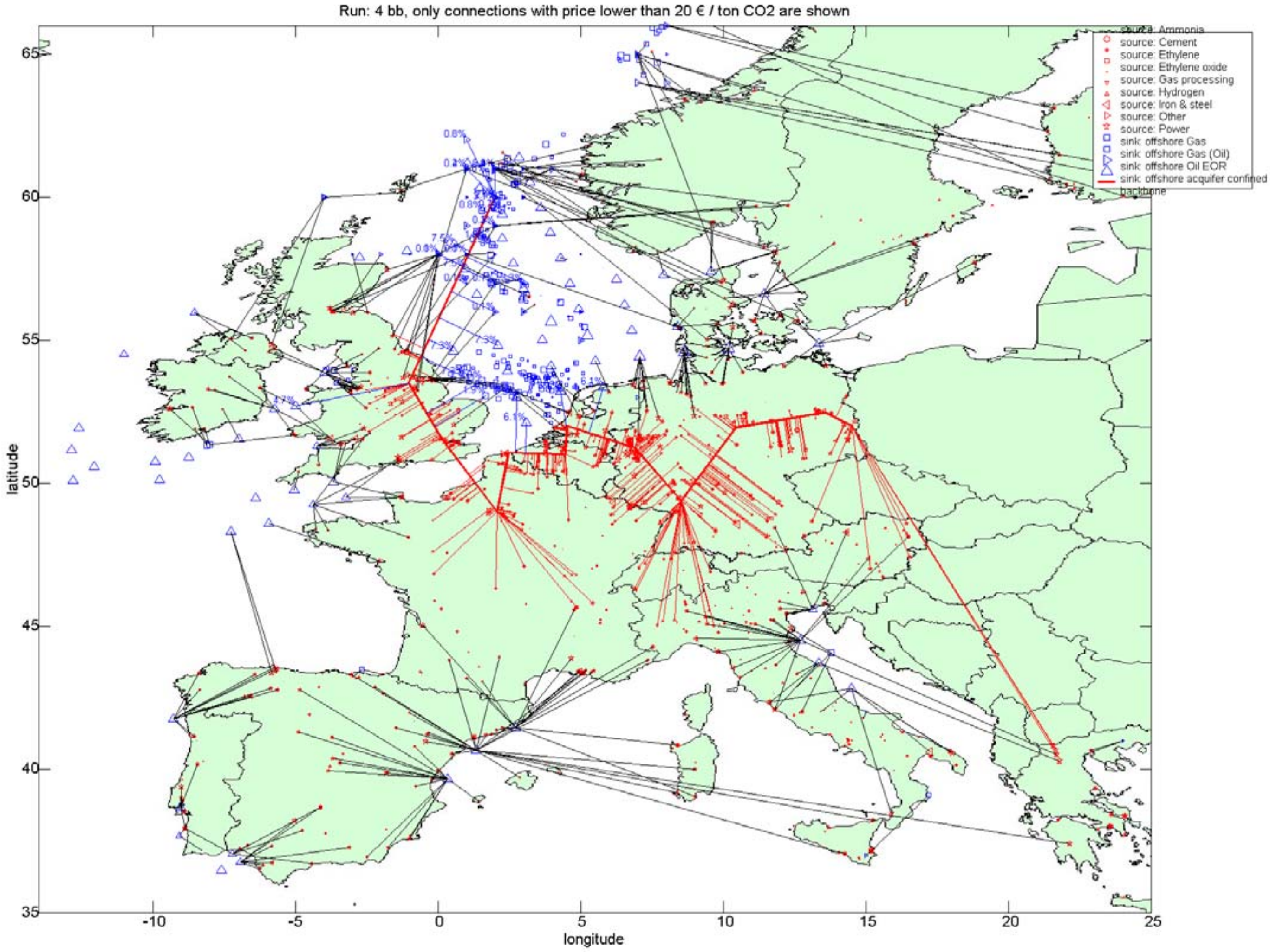
G.4 All identified types of storage structures including oil production offshore (D)

Confined deep saline aquifers, oil fields with incremental oil production, gas fields and deep unminable coal seams, offshore only

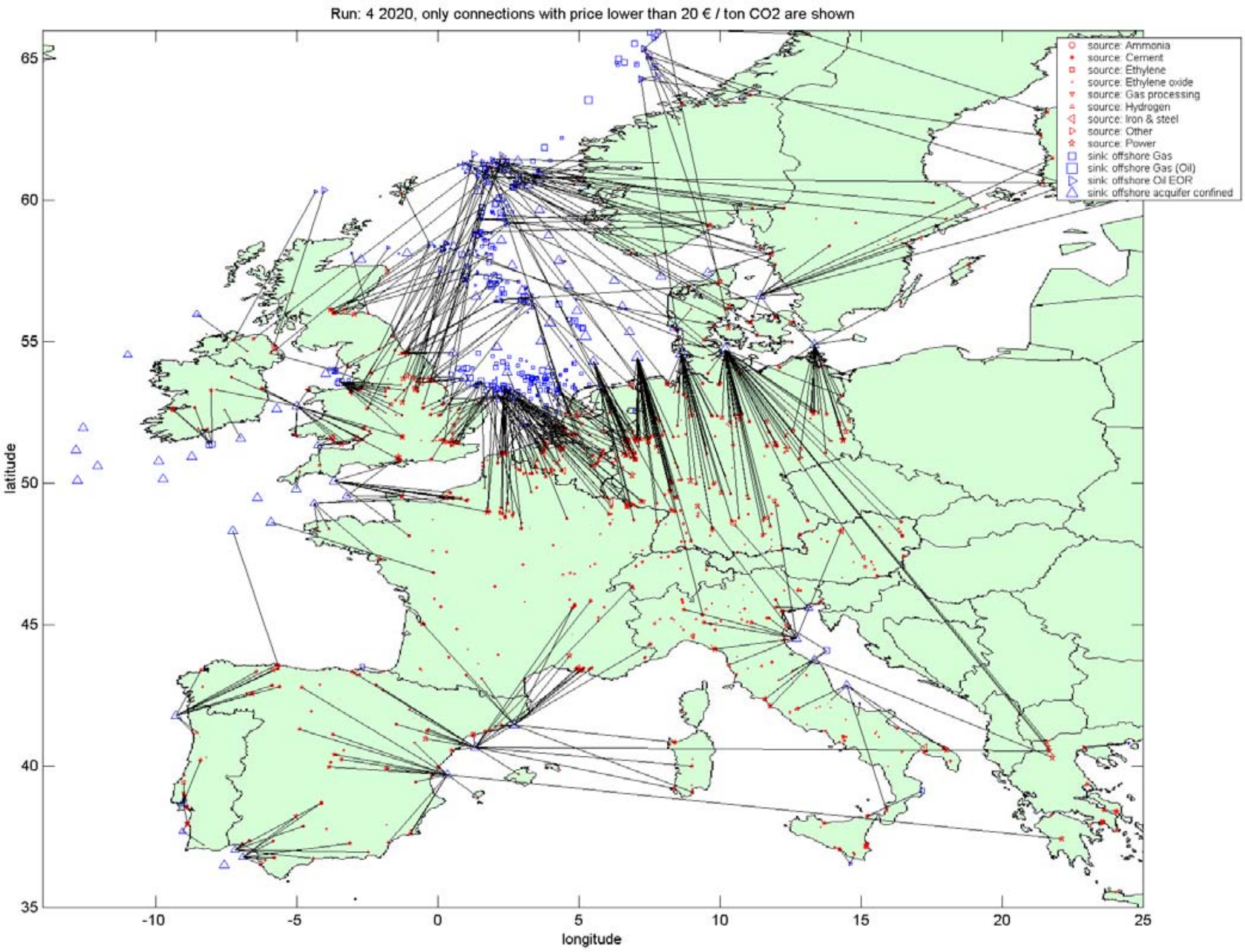
G.4.1 1-1 Implementation scheme D (B 1-1 - 2000)



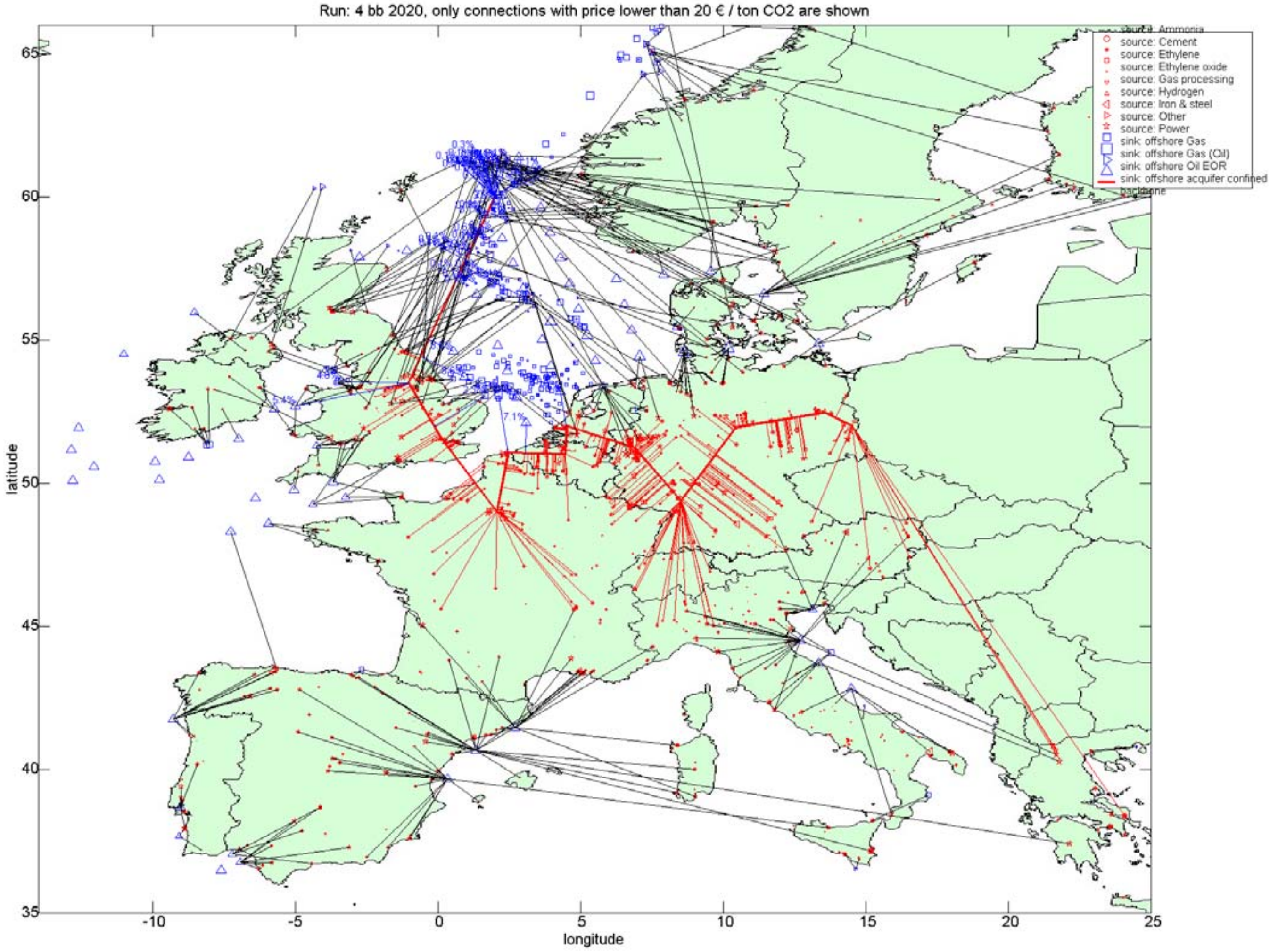
G.4.2 Backbone Implementation scheme D (B bb - 2000)



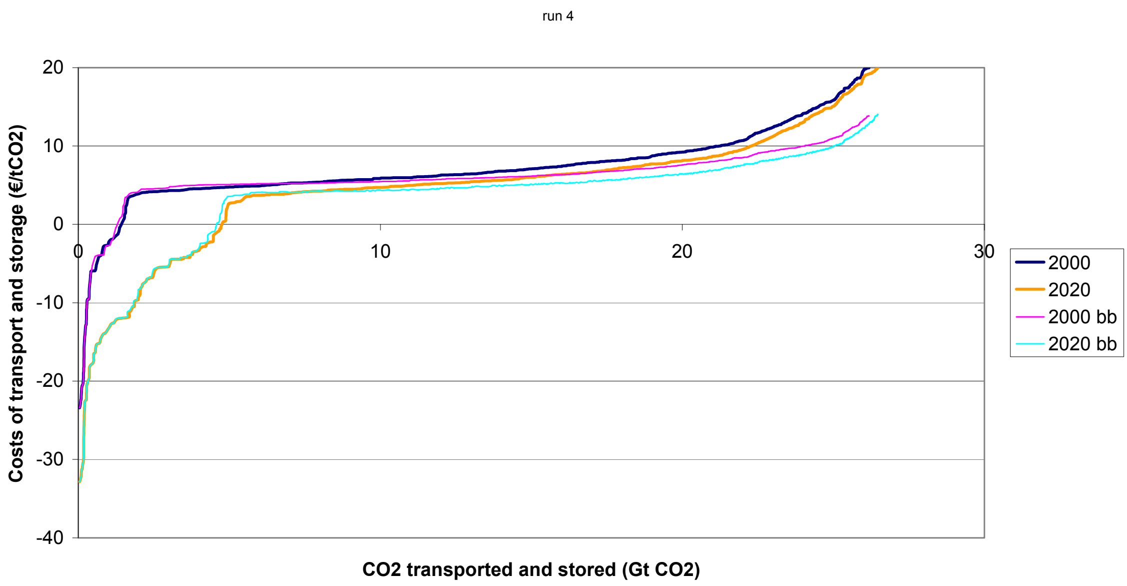
G.4.3 1-1 Implementation scheme D (B 1-1 - 2020)



G.4.4 Backbone Implementation scheme D (B bb - 2020)



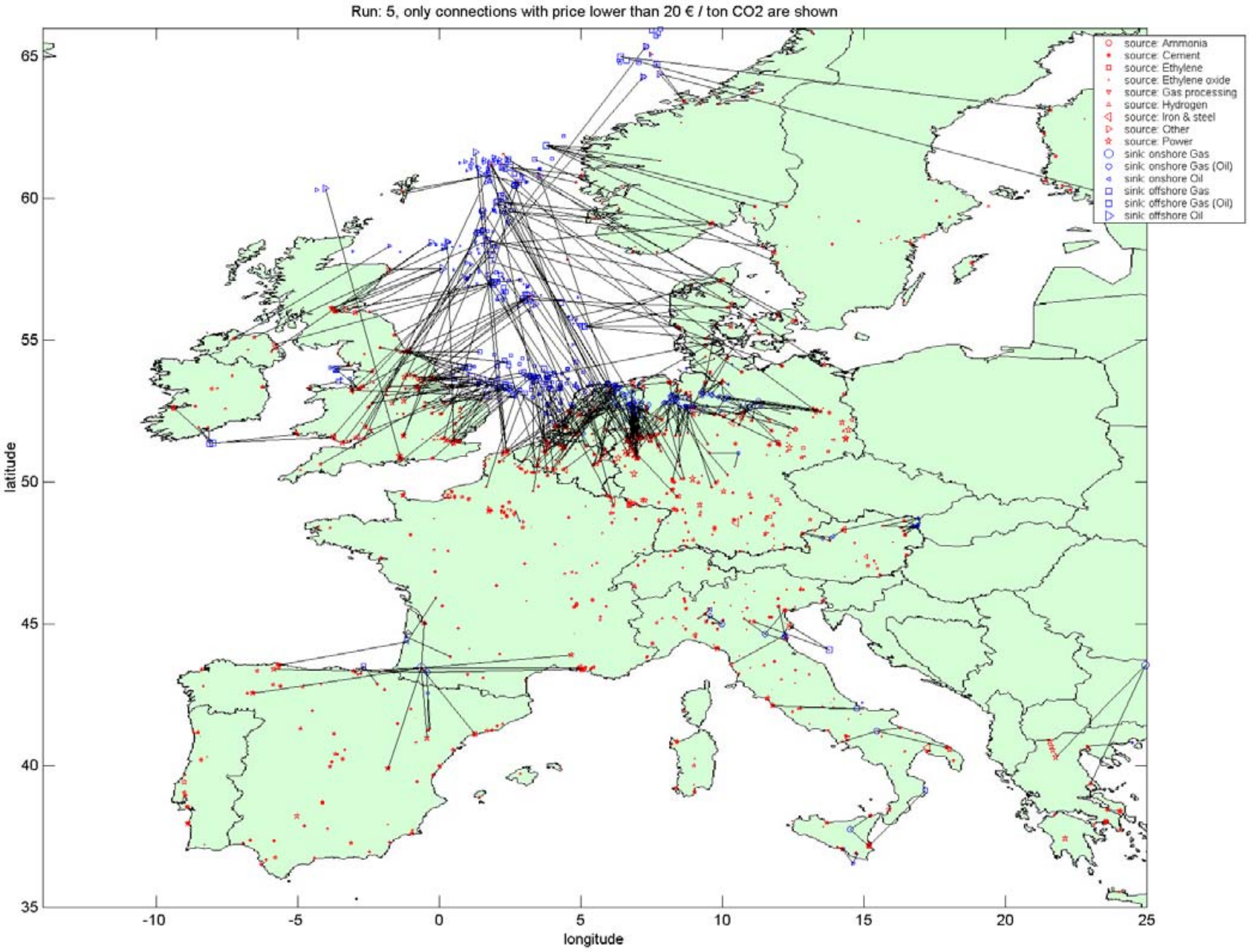
G.4.5 Cost curves scheme D



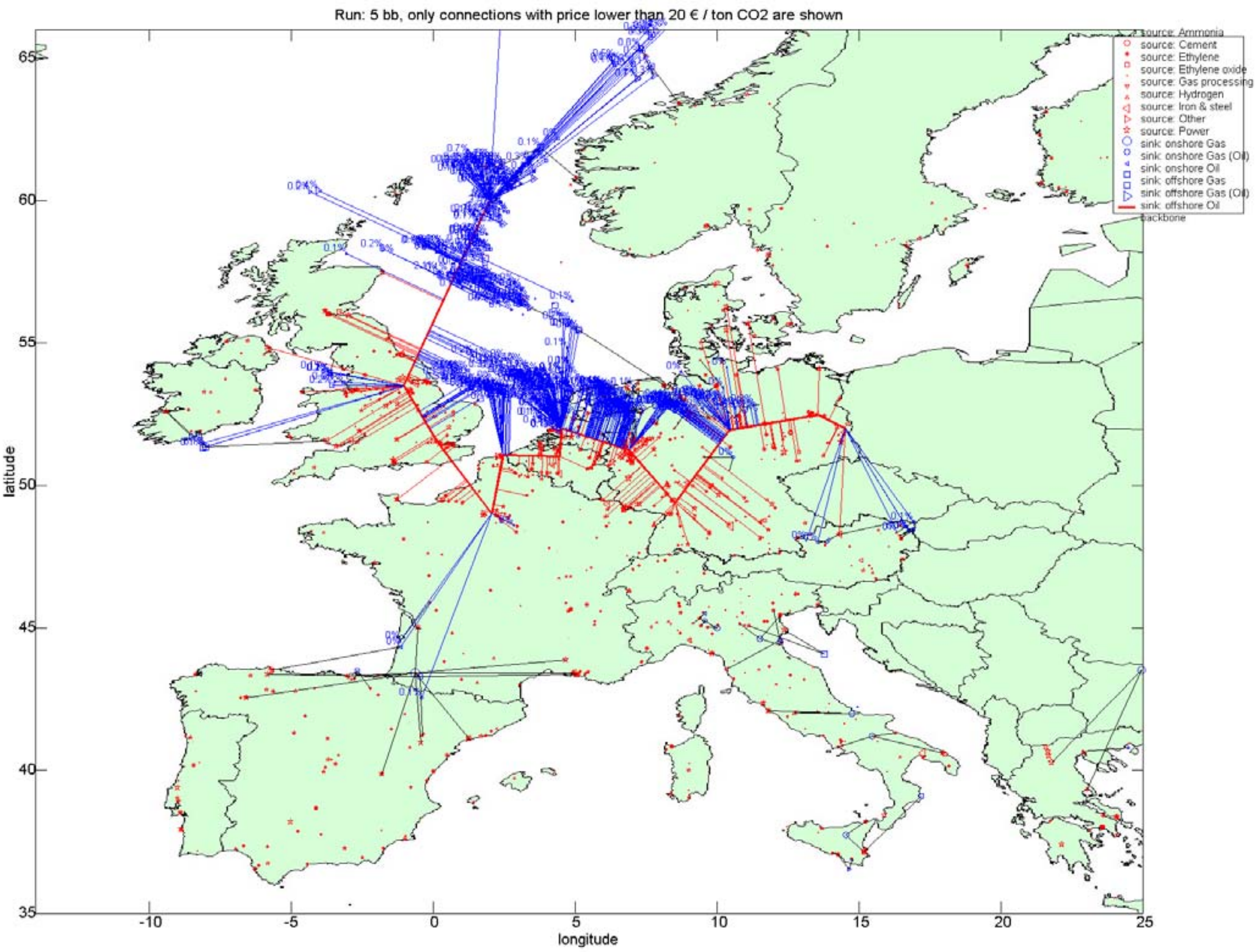
G.5 Hydrocarbon fields ex oil production (E)

Oil fields without incremental oil production and gas fields both off- and onshore

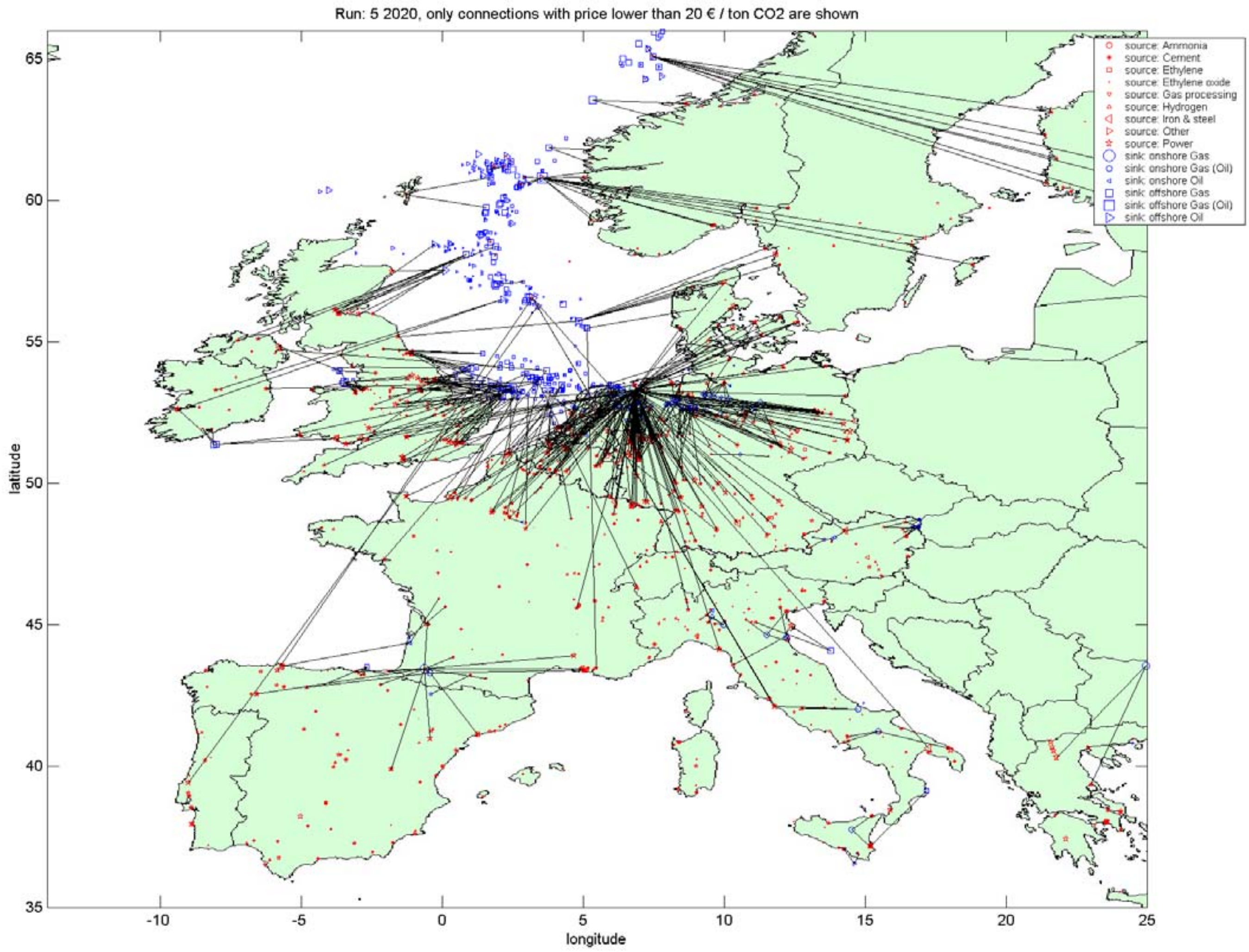
G.5.1 Implementation scheme E (B 1-1 - 2000)



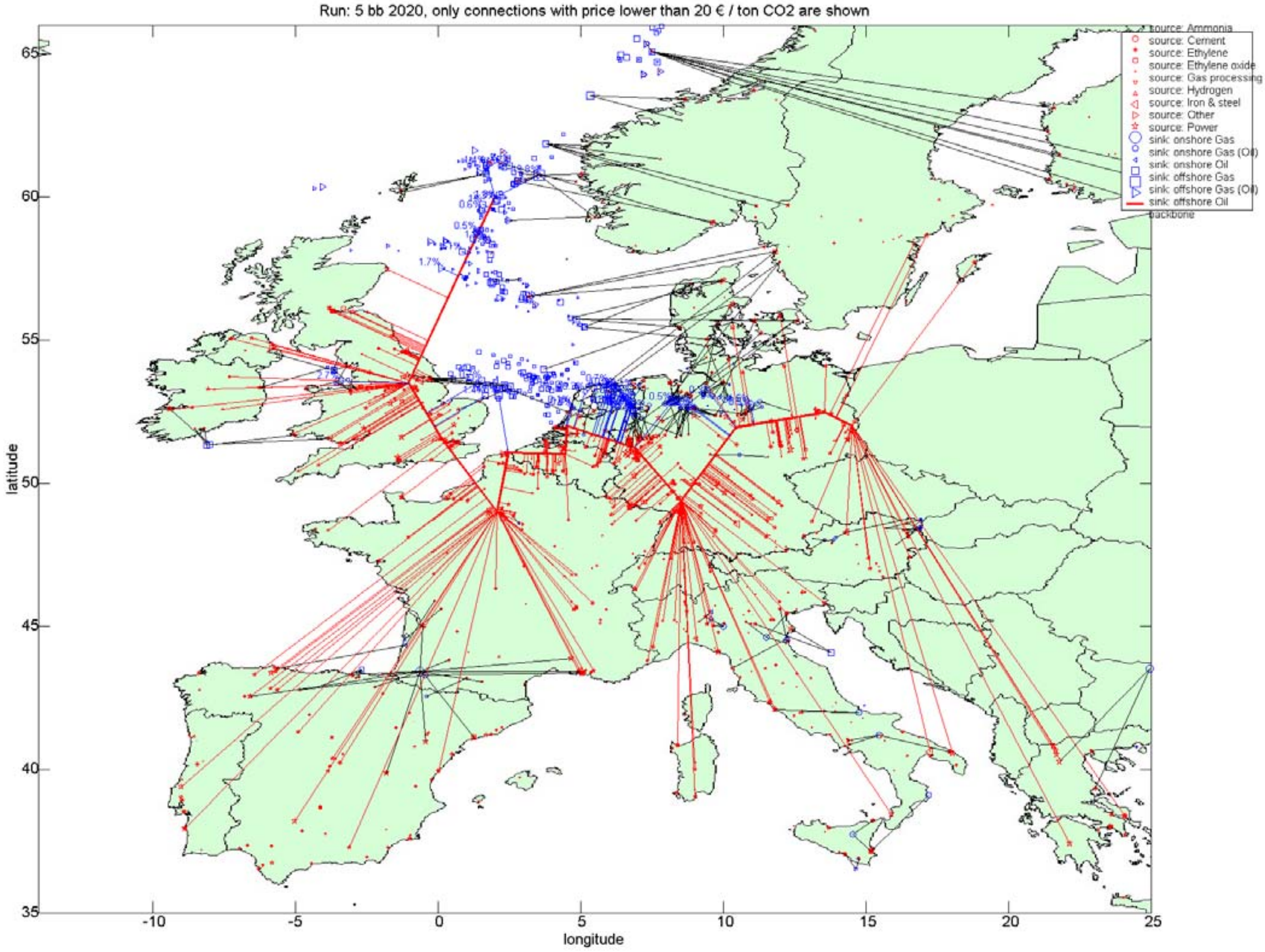
G.5.2 Backbone Implementation scheme E (B bb - 2000)



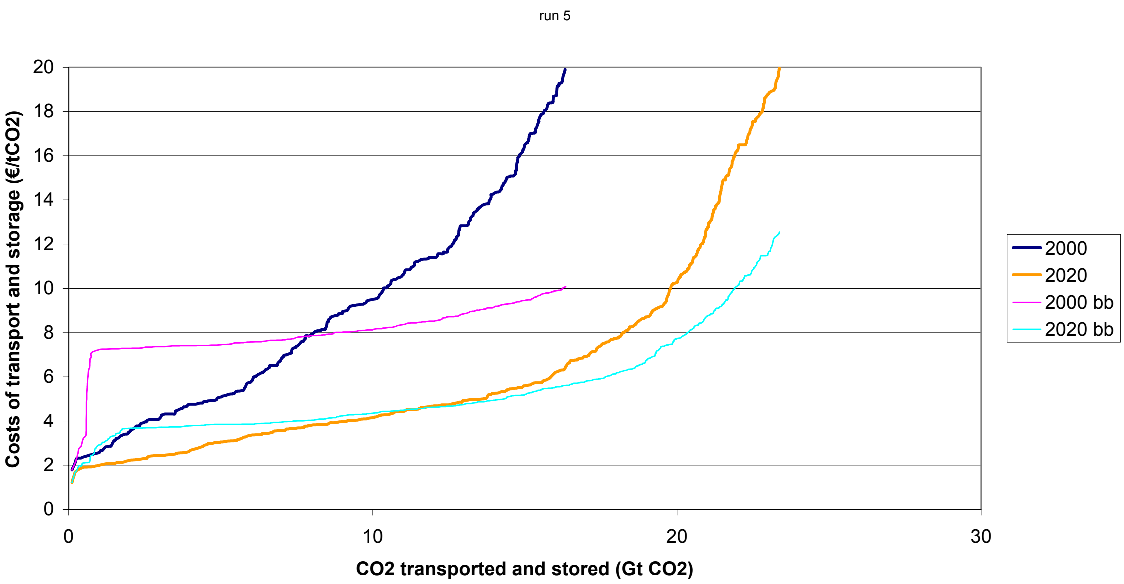
G.5.3 1-1 Implementation scheme E (B 1-1 - 2020)



G.5.4 Backbone Implementation scheme E (B bb - 2020)



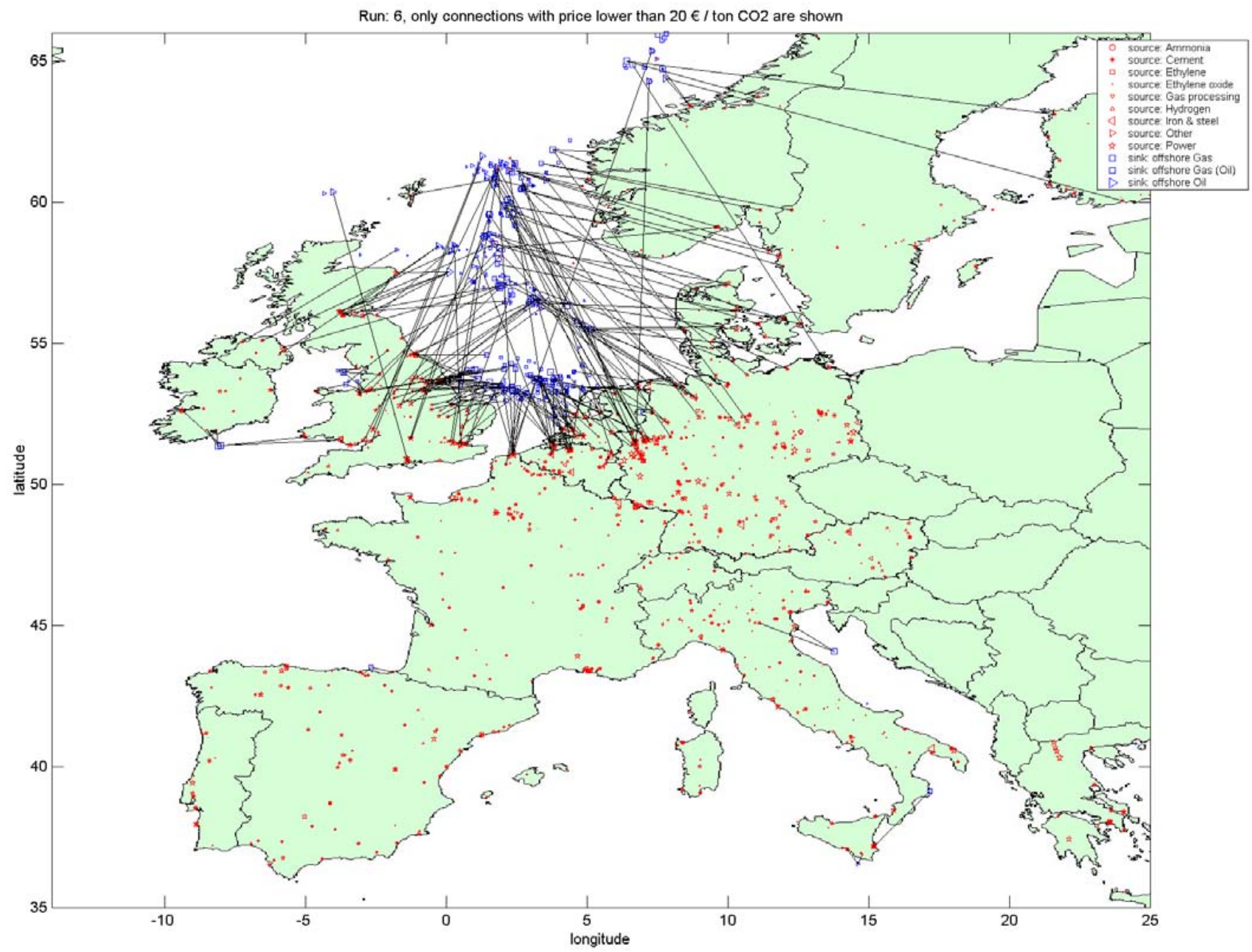
G.5.5 Cost curves scheme E



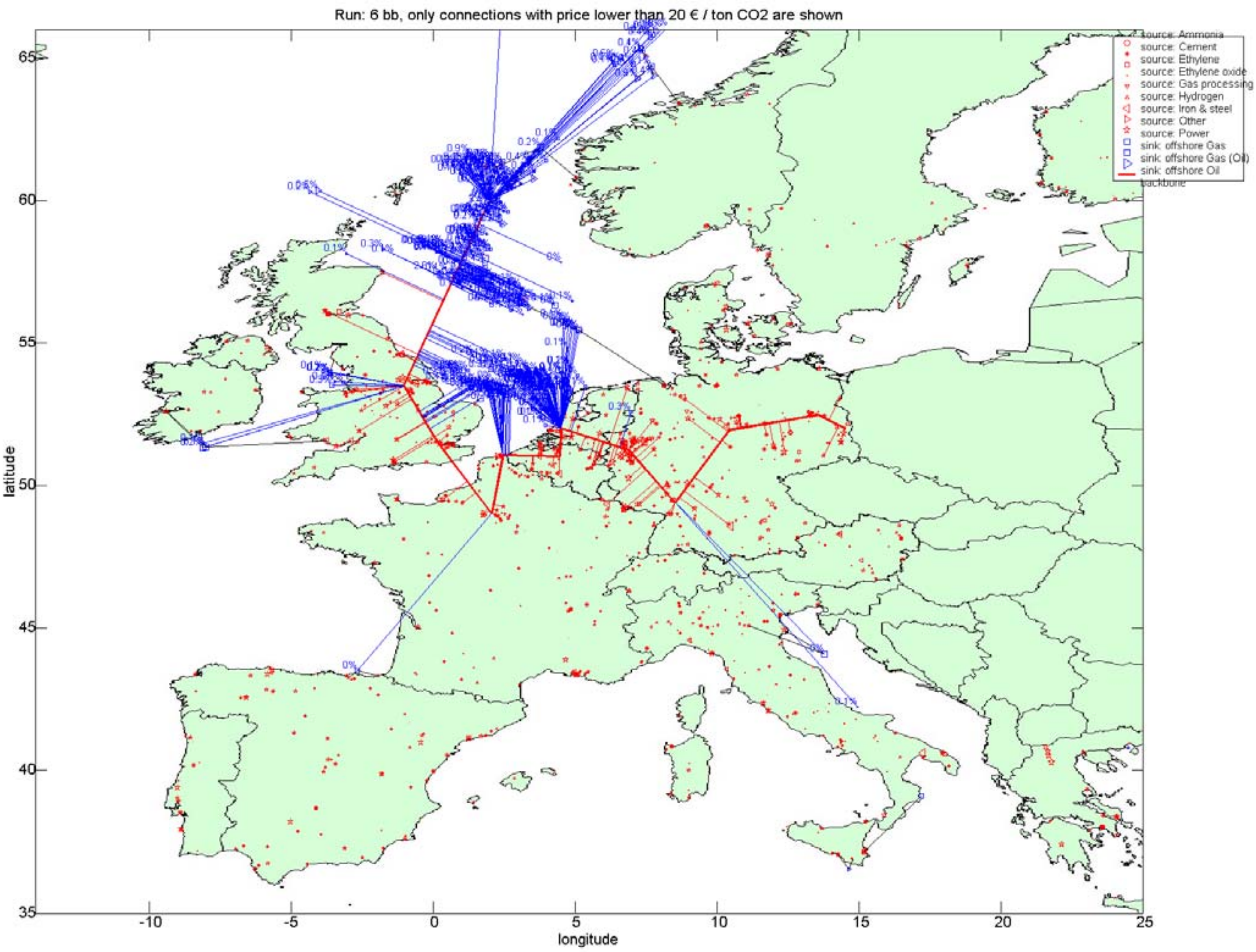
G.6 Hydrocarbon fields ex oil production (E)

Oil fields without incremental oil production and gas fields both off- and onshore

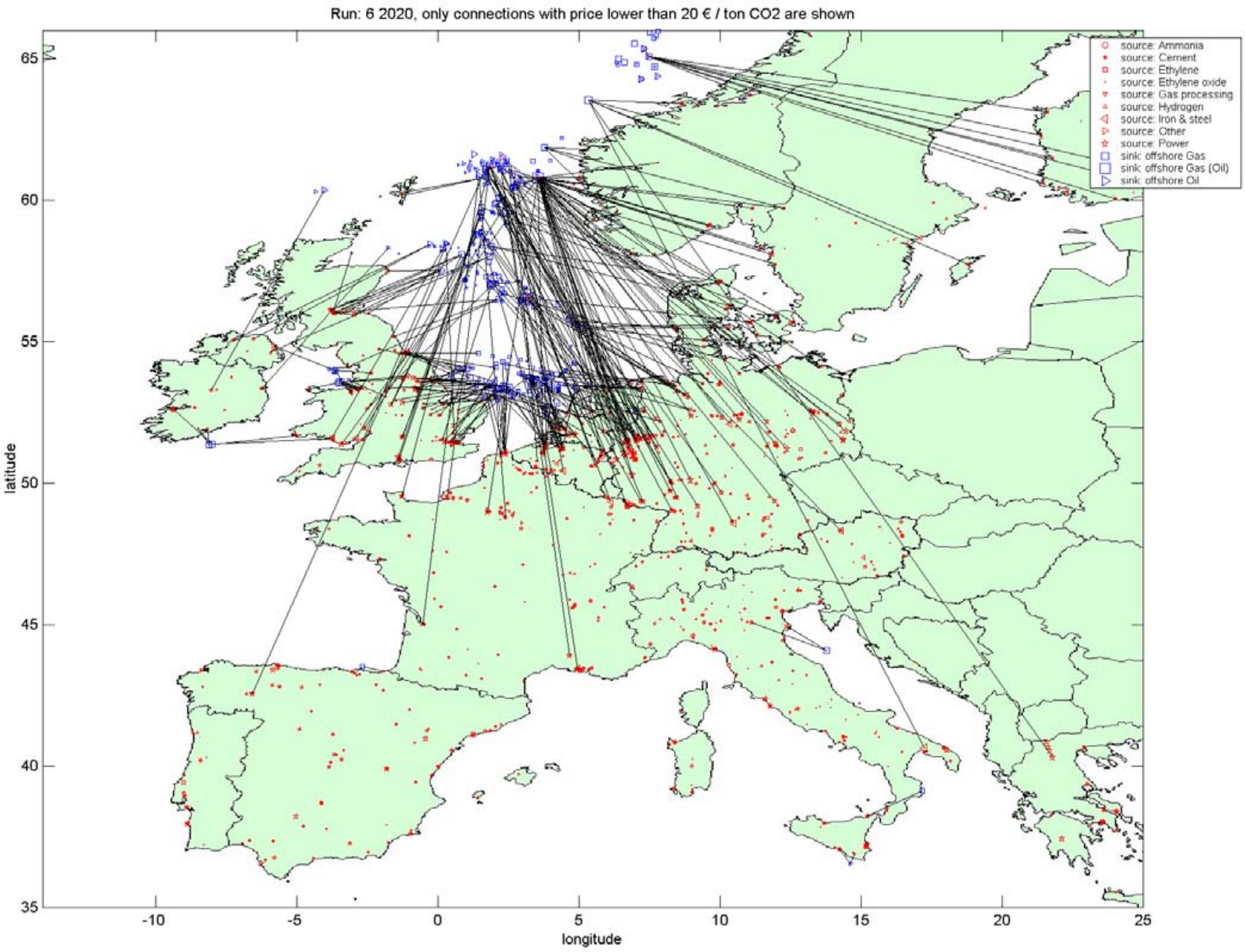
G.6.1 -1 Implementation scheme F (B 1-1 - 2000)



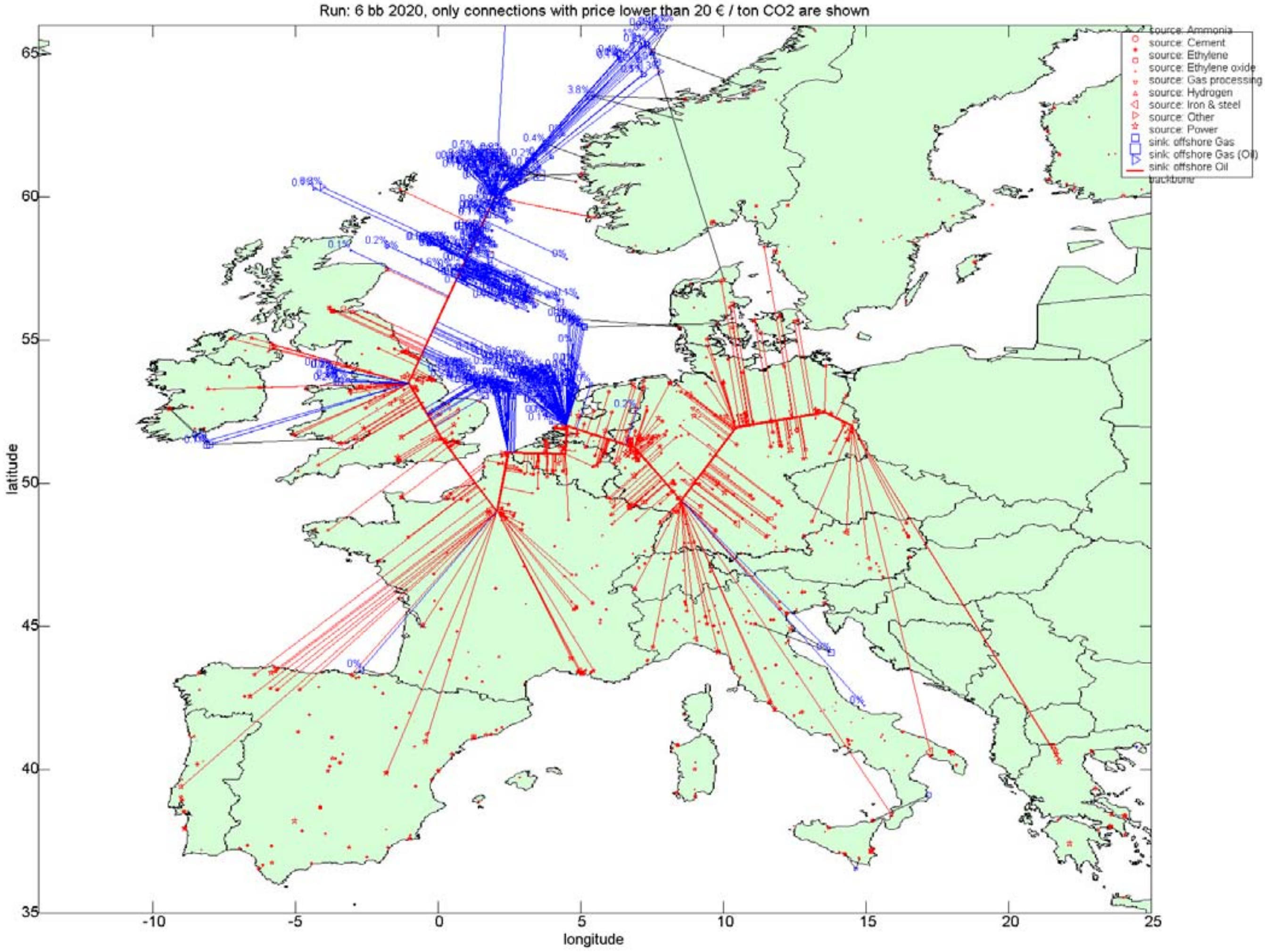
G.6.2 Backbone Implementation scheme F (B bb - 2000)



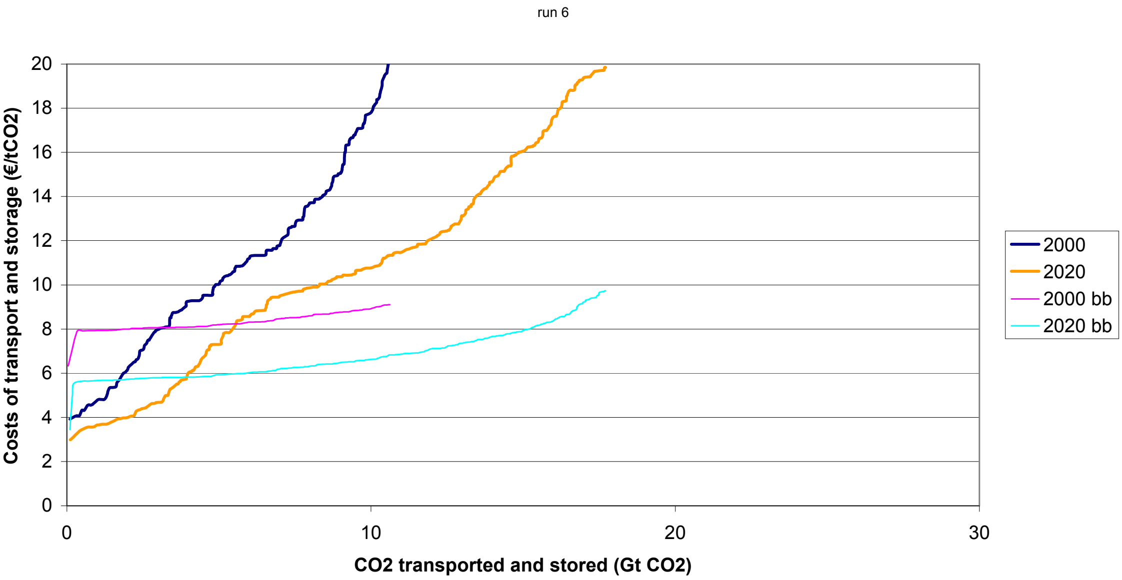
G.6.3 1-1 Implementation scheme F (B 1-1 - 2020)



G.6.4 Backbone Implementation scheme F (B bb - 2020)



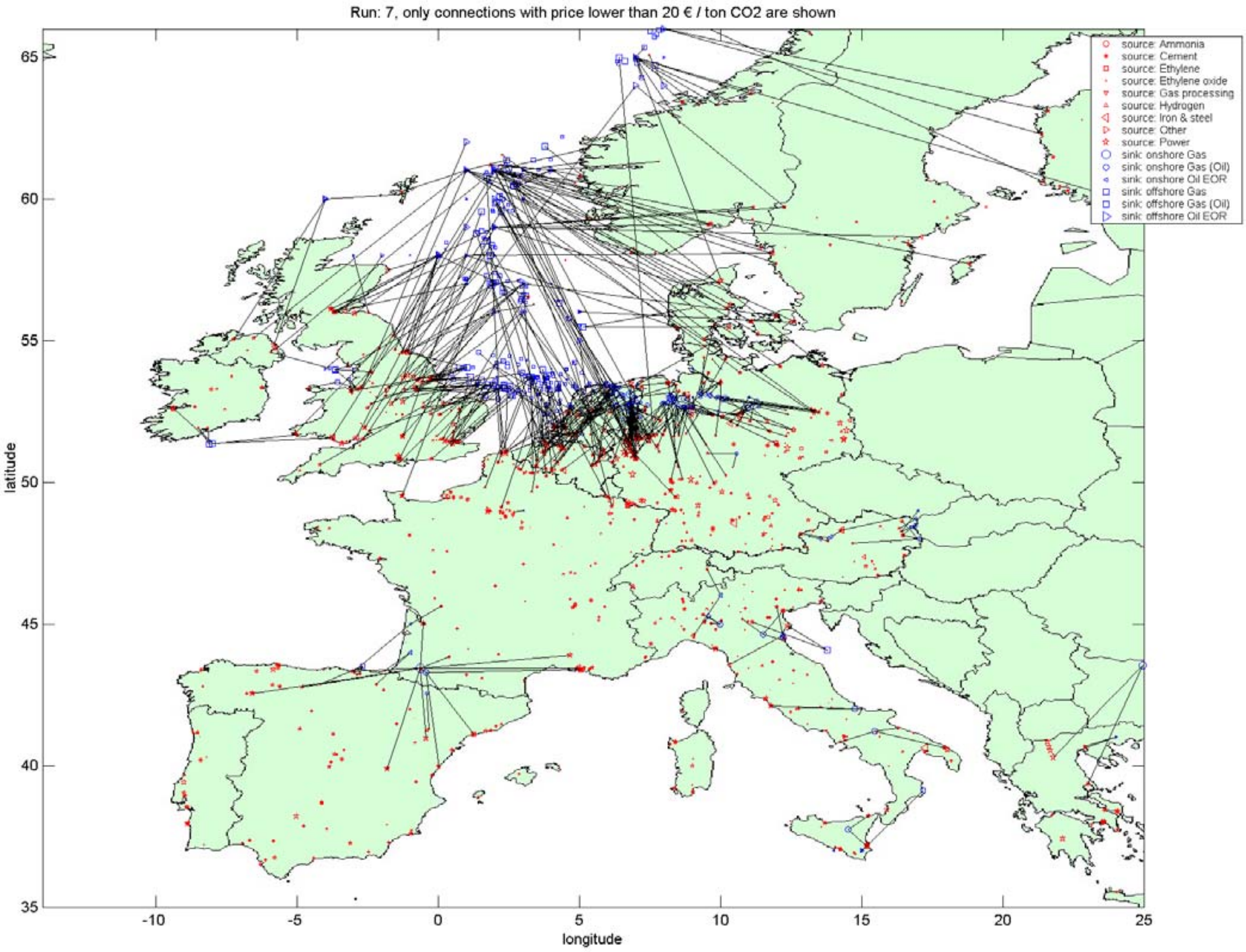
G.6.5 Cost curves scheme F



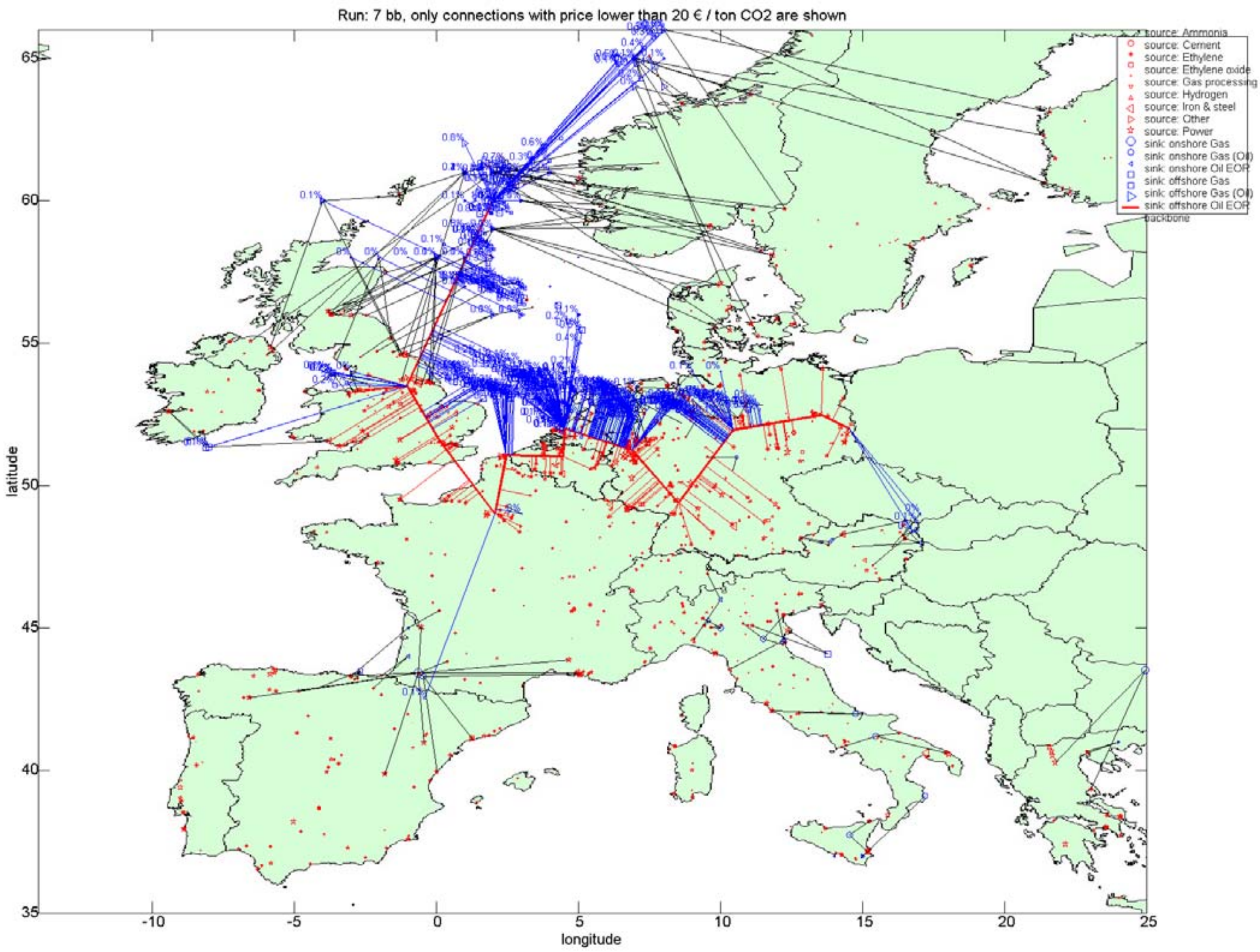
G.7 Hydrocarbon fields with oil production (G)

Oil fields with incremental oil production and gas fields both on- and offshore

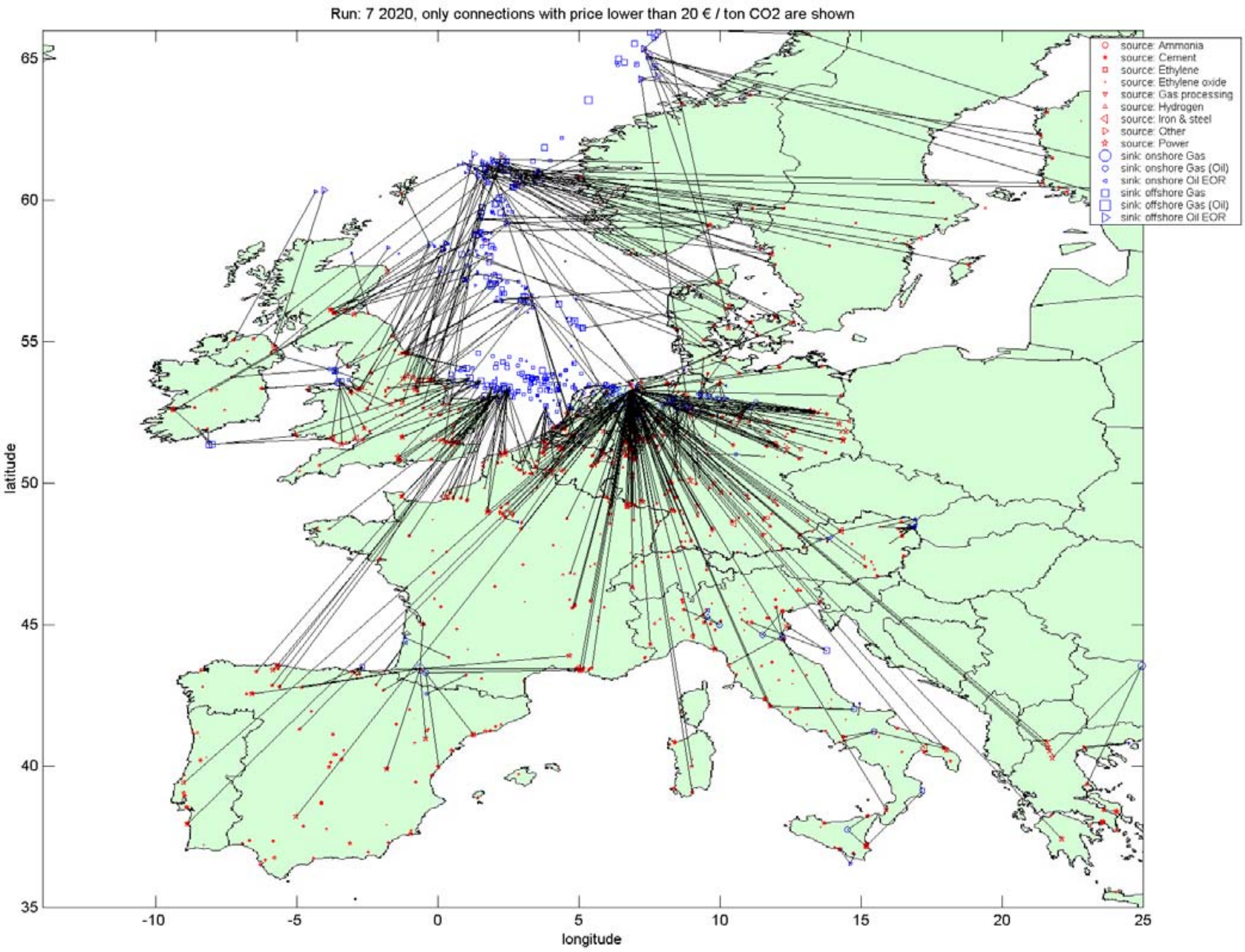
G.7.1 Implementation scheme G (B 1-1 - 2000)



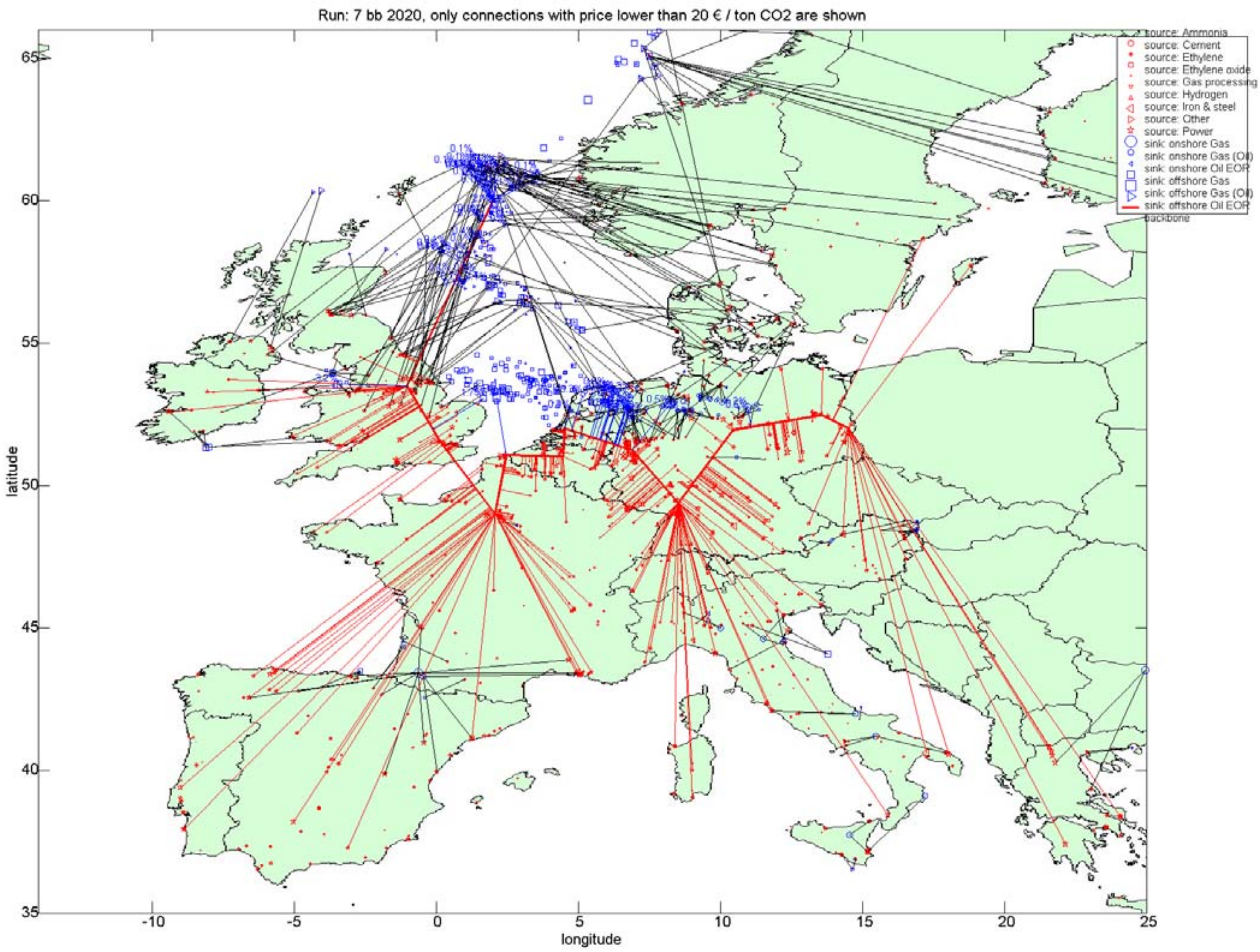
G.7.2 Backbone Implementation scheme G (B bb - 2000)



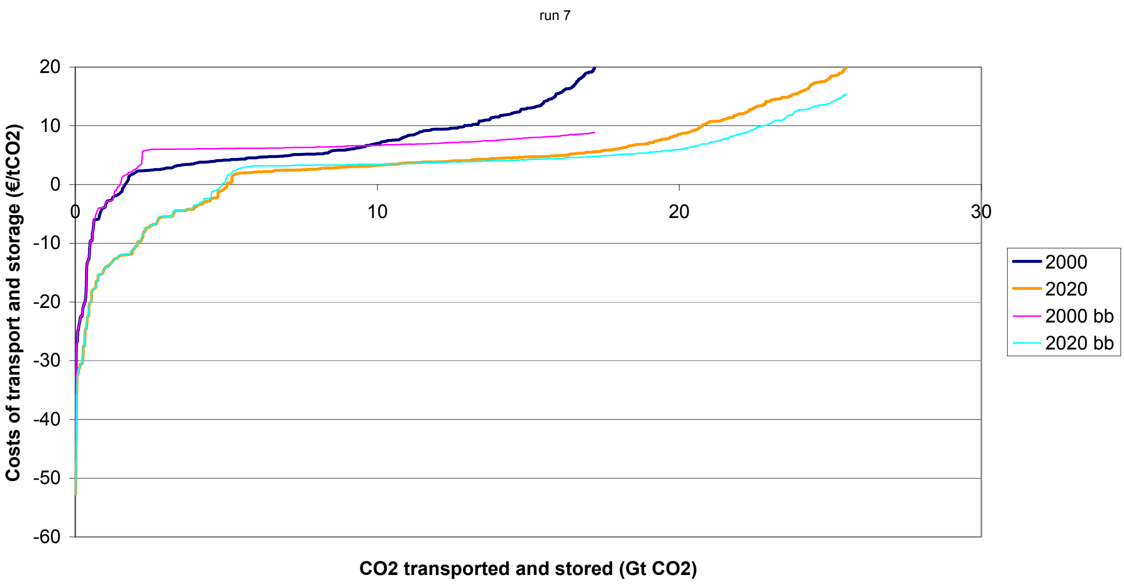
G.7.3 1-1 Implementation scheme G (B 1-1 - 2020)



G.7.4 Backbone Implementation scheme G (B bb - 2020)



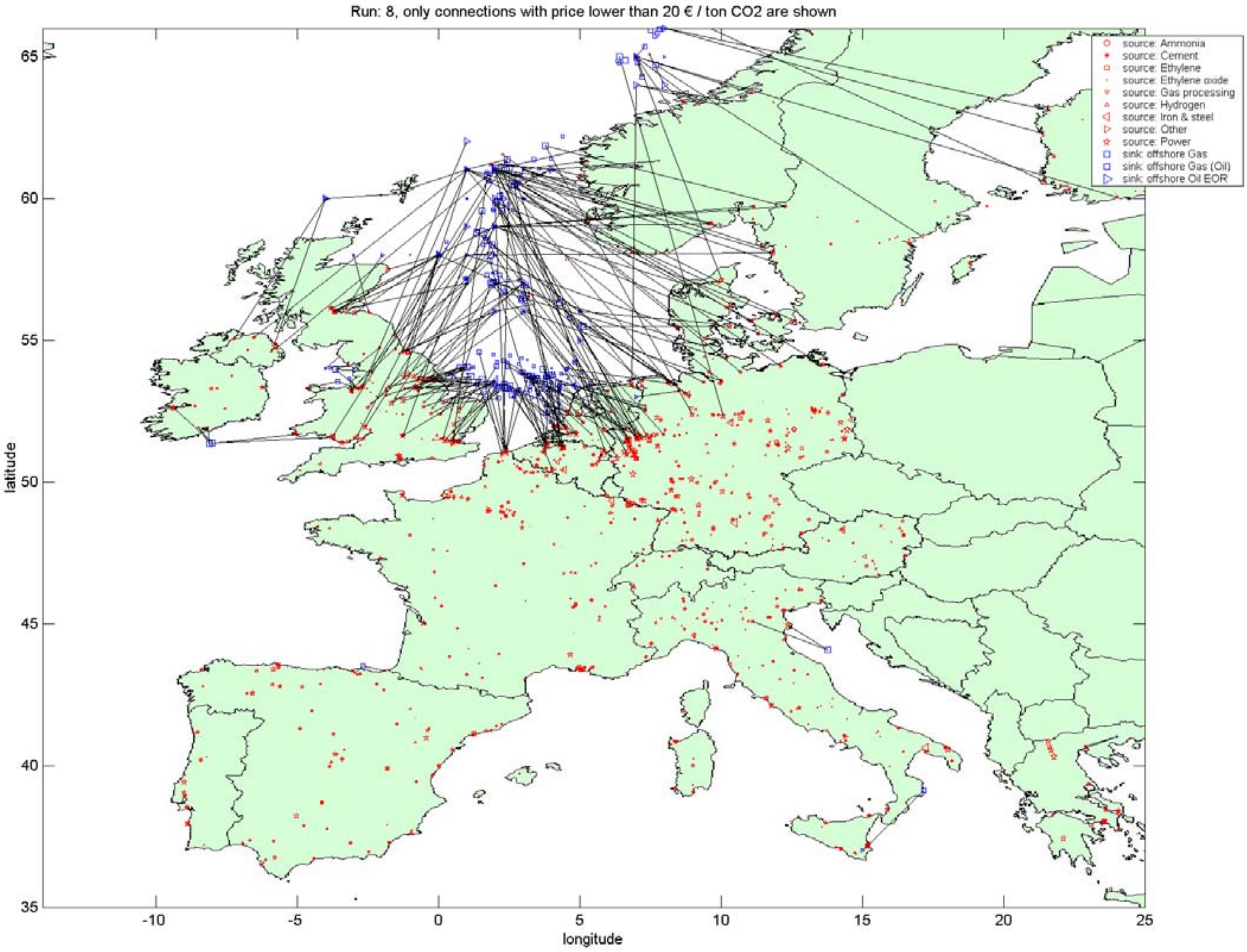
G.7.5 Cost curves scheme G



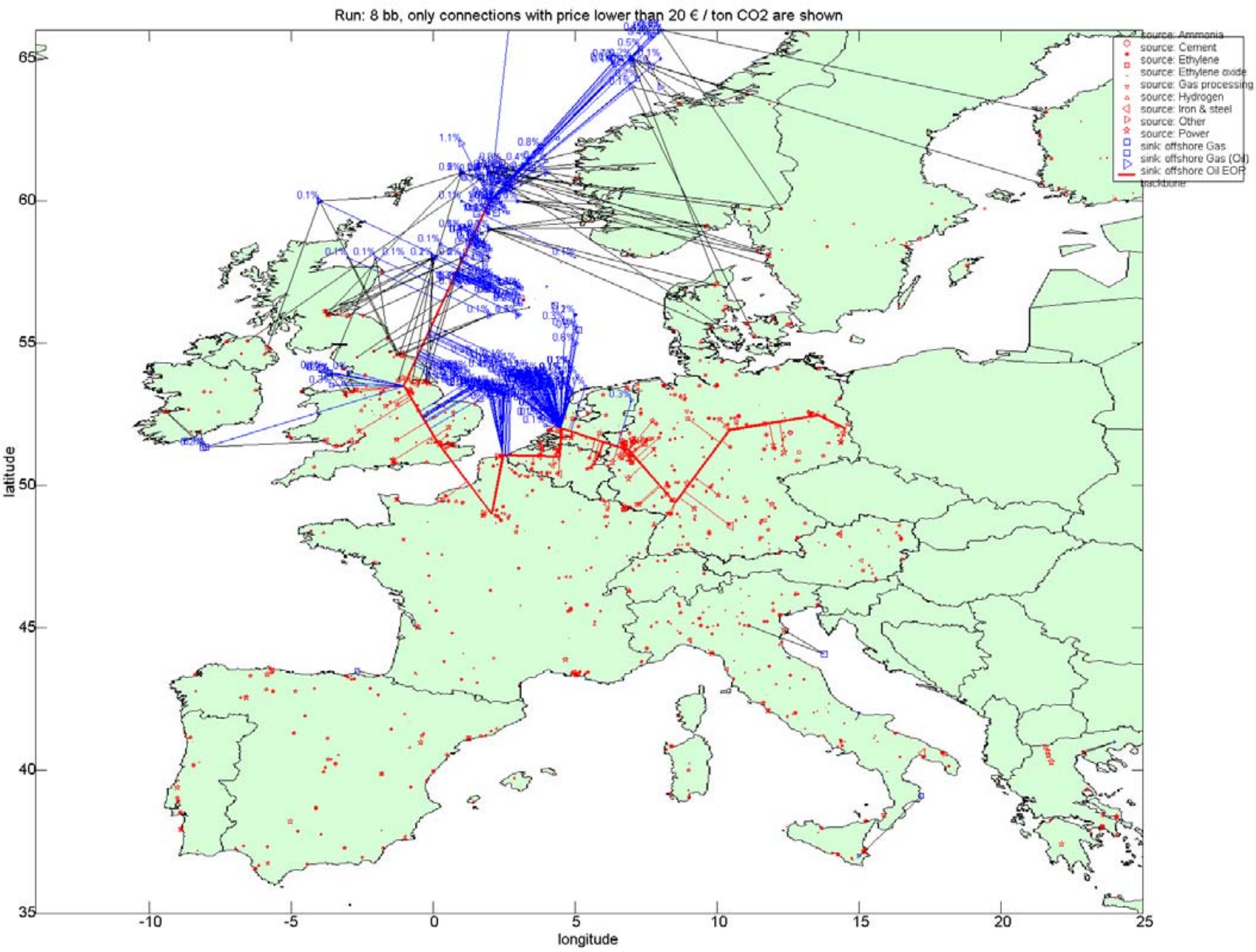
G.8 Offshore hydrocarbon fields with oil production (H)

Oil fields with incremental oil production and gas fields, offshore only.

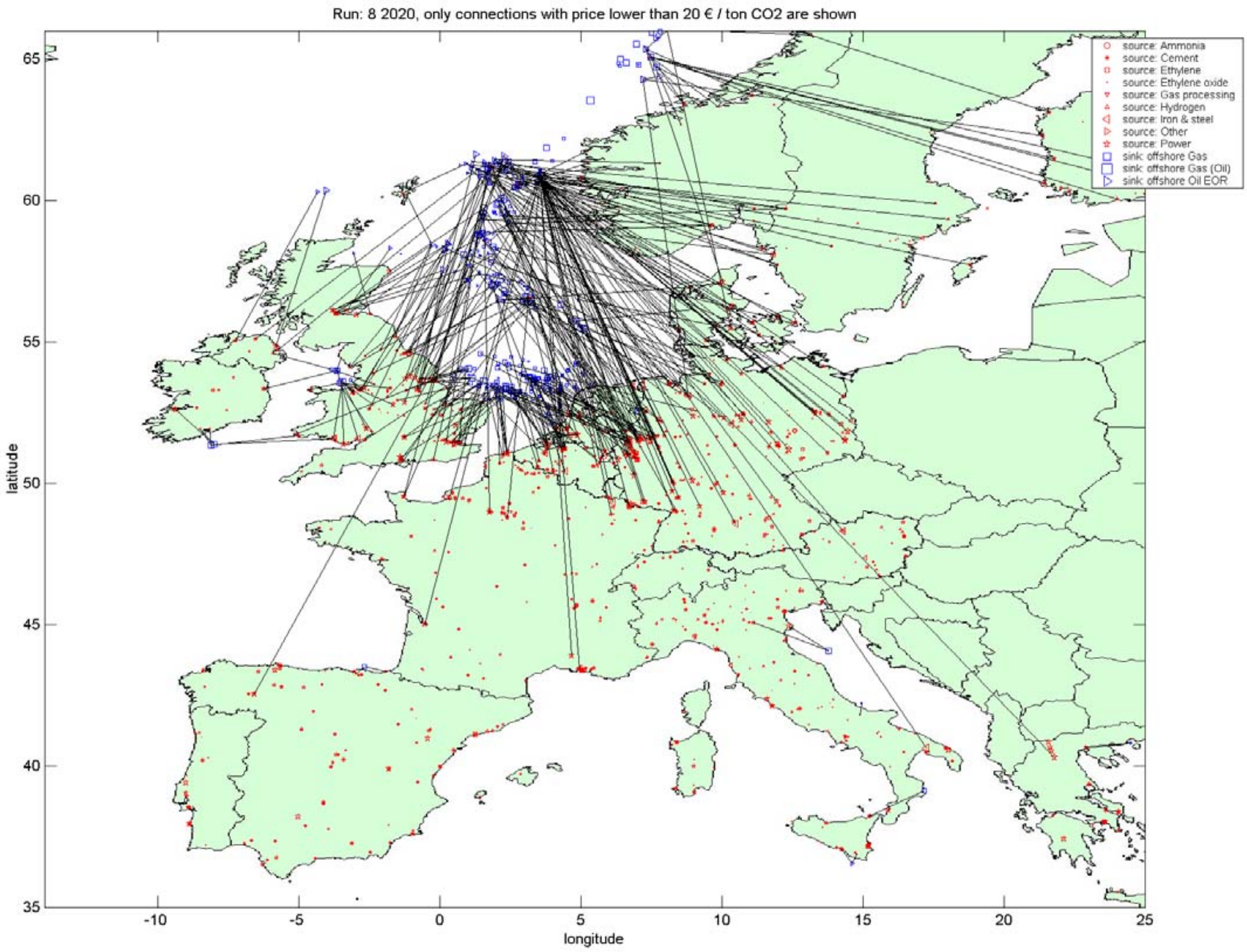
G.8.1 1-1 Implementation scheme H (B 1-1 - 2000)



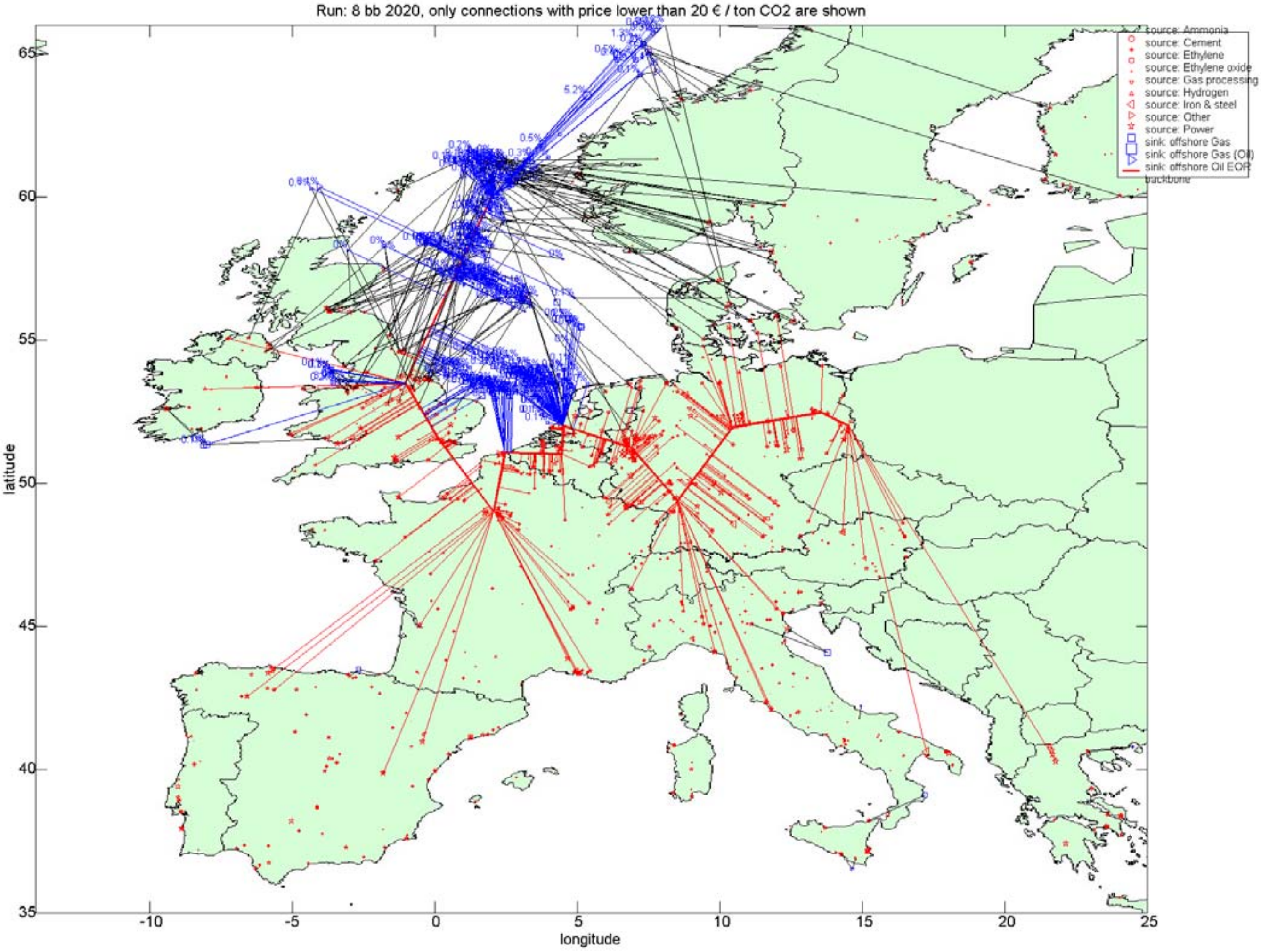
G.8.2 Backbone Implementation scheme H (B bb - 2000)



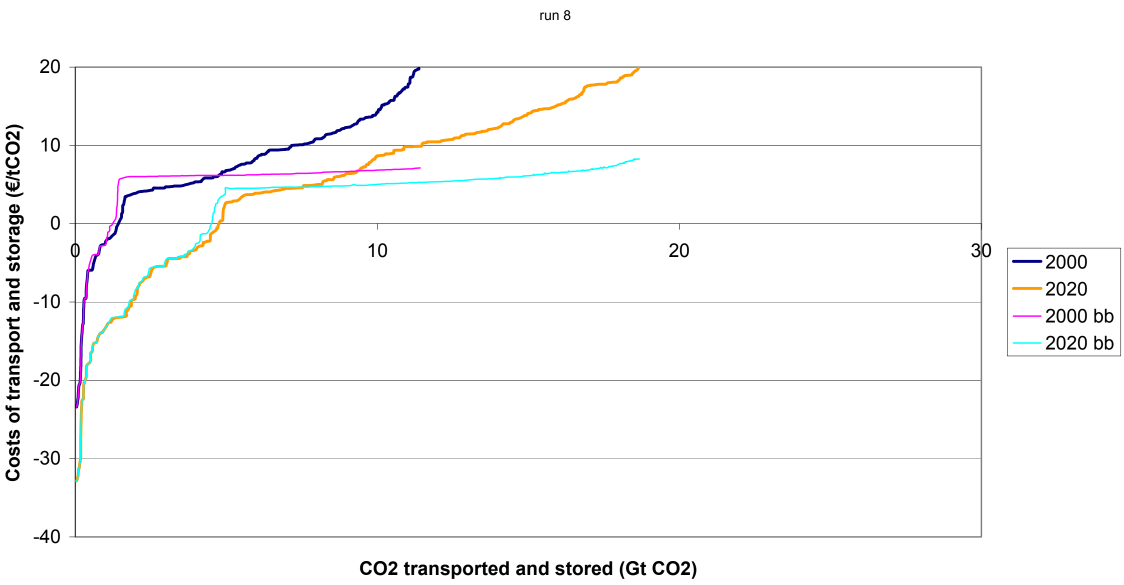
G.8.3 1-1 Implementation scheme H (B 1-1 - 2020)



G.8.4 Backbone Implementation scheme H (B bb - 2020)

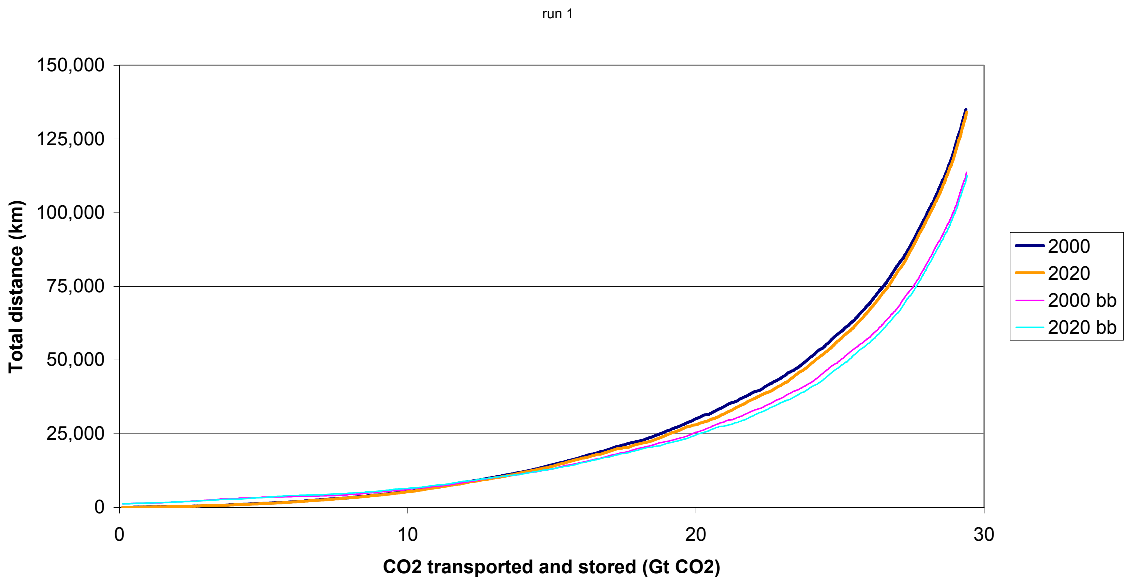


G.8.5 Cost curves scheme H

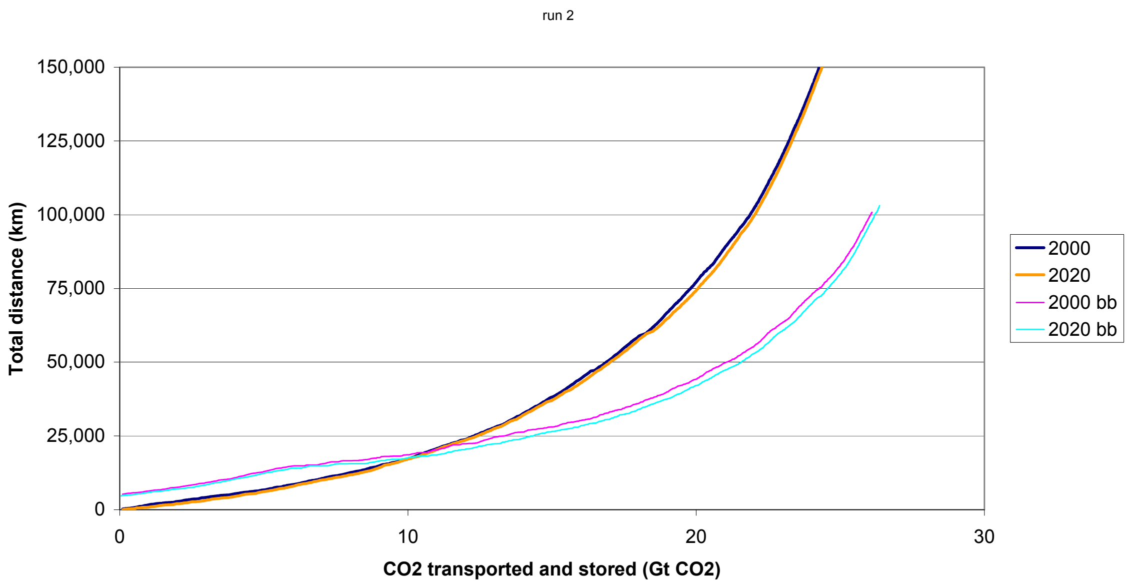


H Cumulative pipeline length

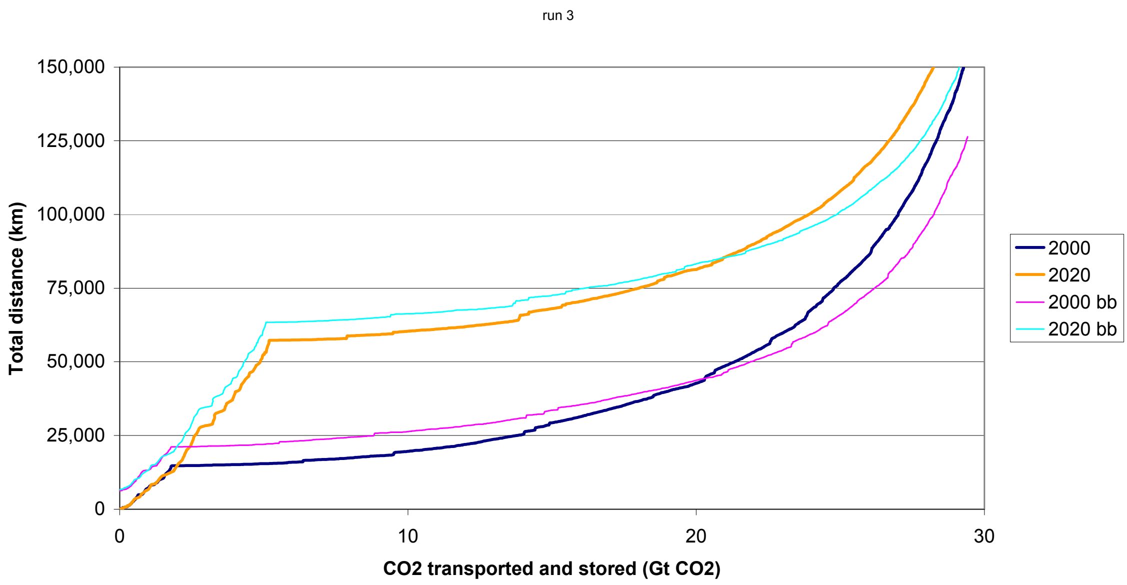
H.1.1 Cumulative transport distance for scheme A



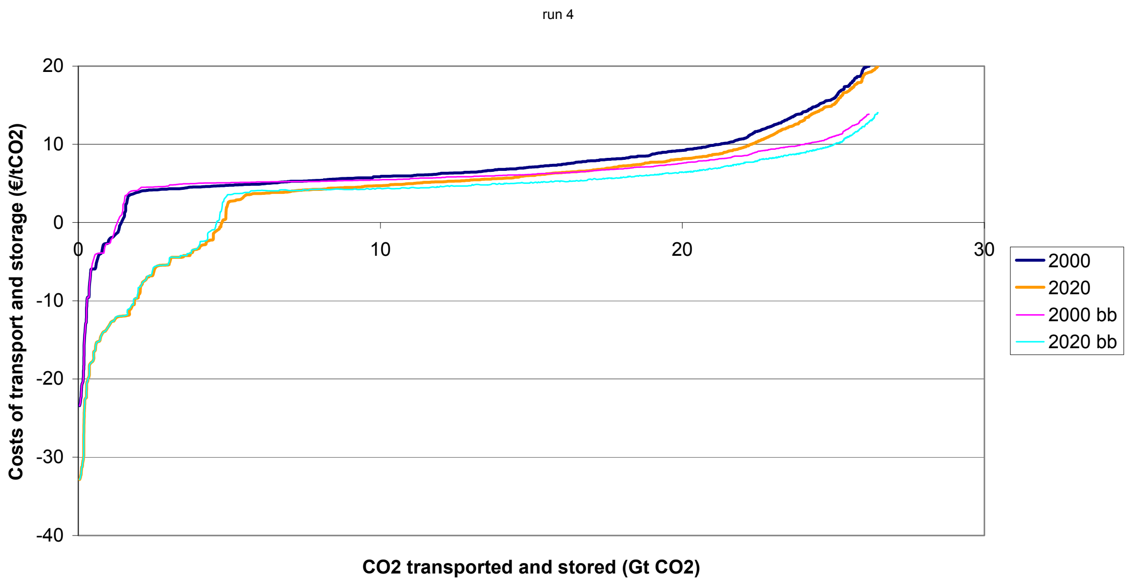
H.1.2 Cumulative transport distance for scheme B



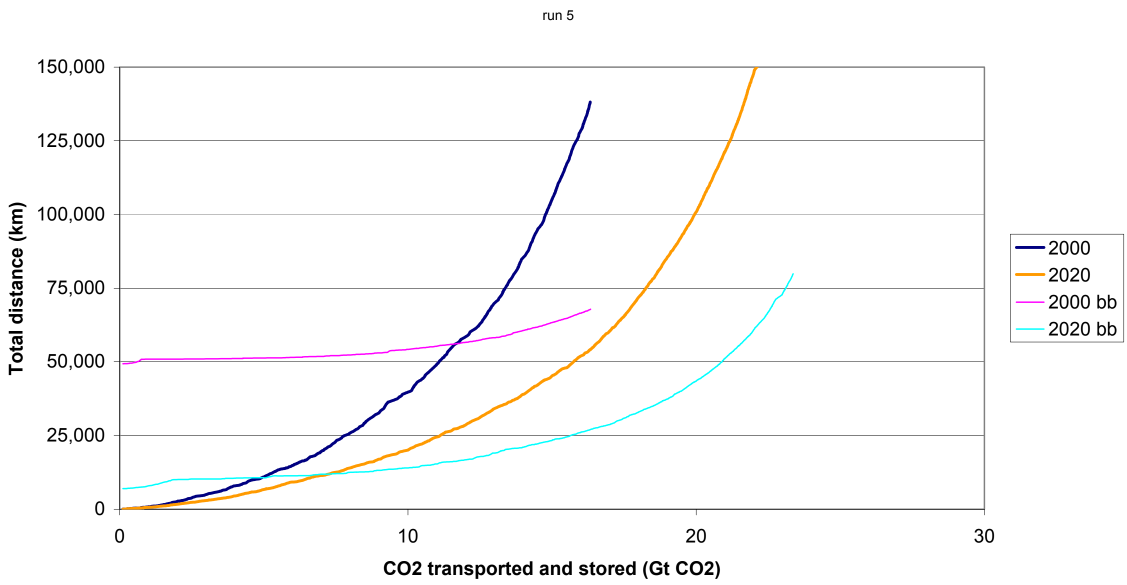
H.1.3 Cumulative transport distance for scheme C



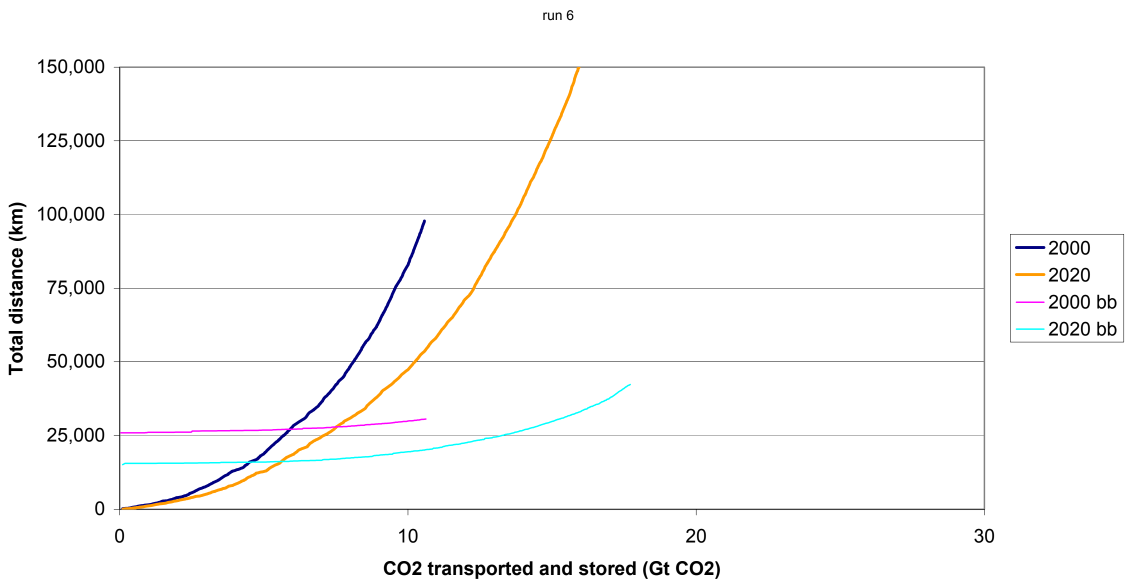
H.1.4 Cumulative transport distance for scheme D



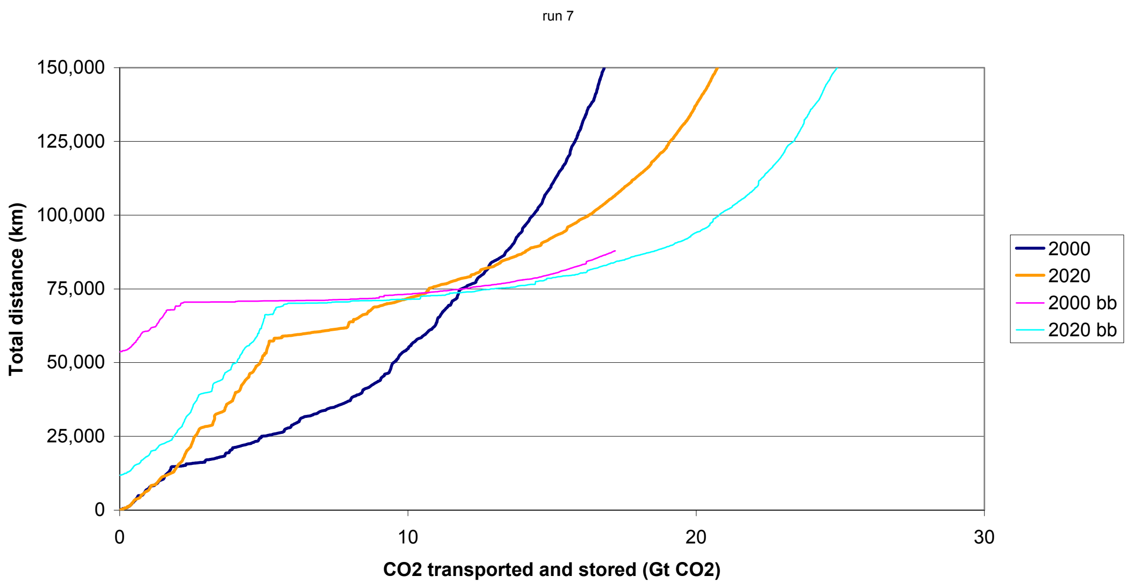
H.1.5 Cumulative transport distance for scheme E



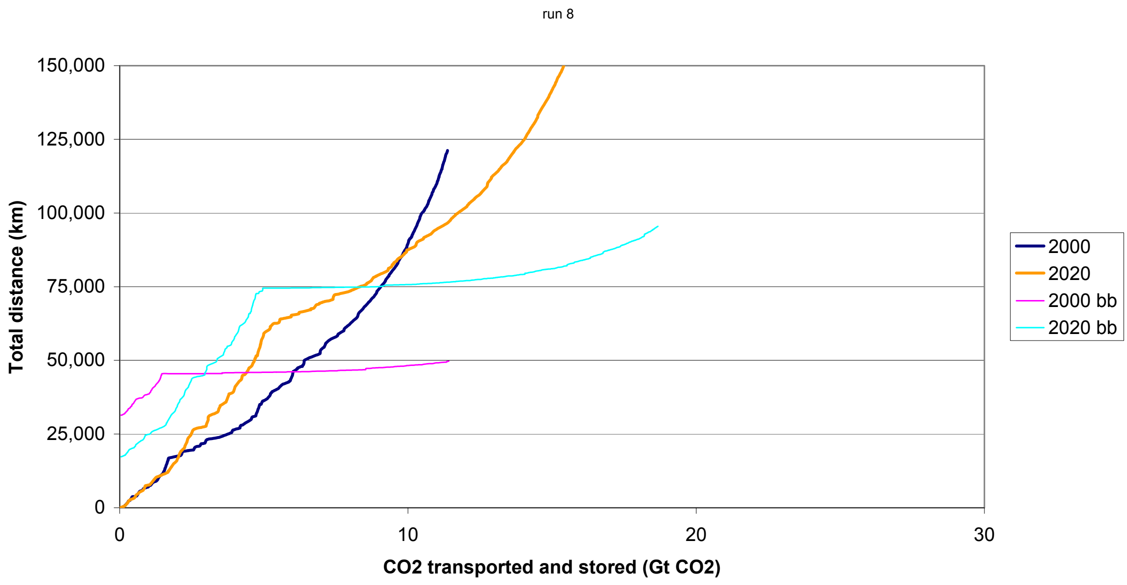
H.1.6 Cumulative transport distance for scheme F



H.1.7 Cumulative transport distance for scheme G

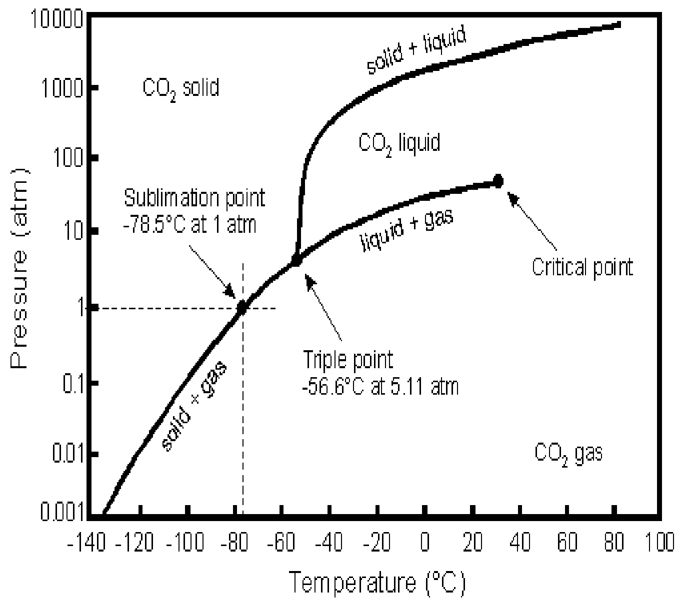


H.1.8 Cumulative transport distance for scheme H



I Transport conditions

The optimal transport pressure of the carbon dioxide depends on a number of factors. Firstly, the density must be sufficient to make the best use of the pipeline capacity. Secondly, phase transition in the pipeline from liquid to the gaseous phase, should be avoided. Phase transition is for two reasons unwanted. It may cause cavitation; close to the transition stage turbulence may occur. This may cause carbon dioxide to boil locally and pipeline may be damaged. Also the density of the carbon dioxide will substantially increase, resulting in a significant lower transport capacity. It is therefore important to determine the right conditions to transport of the carbon dioxide. The critical pressure of carbon dioxide is 7.5 MPa, and the critical temperature 31.0 ºC. The density of the carbon dioxide at that point is 466 kg/m^3. At lower temperatures (often the condition the carbon dioxide is transported), the carbon dioxide is in the liquid phase. The text box below shows a simplified phase diagram for carbon dioxide and a short explanation.



Pressure-Temperature phase diagram for CO_2.

There are two unique points on this phase diagram. The lower point is called the "triple point" and is the unique combination of temperature and pressure at which all three phases exist simultaneously. The second unique point is the critical point. It can be shown experimentally that for every liquid there is a point along the boiling point curve where the line between the liquid and gaseous phases disappears. At temperatures higher there is only a single phase, which is a very dense gas, or frequently called a critical fluid. At the critical temperature or above the material can no longer compress to a liquid no matter how much pressure is applied. These critical fluids have extremely unique properties. For example, supercritical carbon dioxide is used for the extraction of caffeine from coffee and tea and in enhanced oil recovery operations.

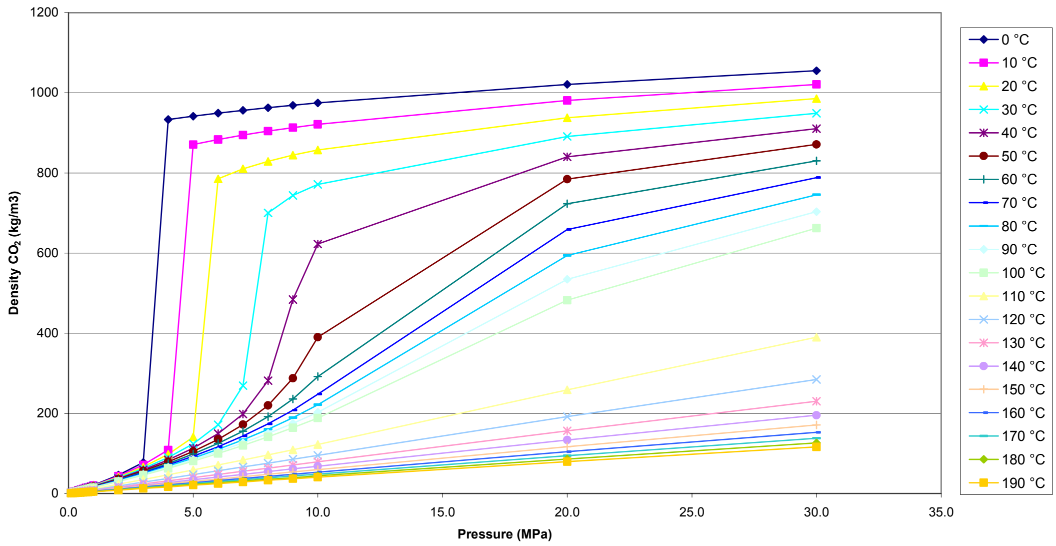


Figure I.1 Density of carbon dioxide as function of the pressure for various temperatures (°C).

Temperature and pressure of the carbon dioxide, however, might change during transport. Temperature is influenced by possible pressure loss during transport, heat production by resistance at the pipe wall, and most importantly by heat exchange with the environment.

Wall resistance causes pressure loss. The extent to which pressure loss occurs depends on the pipe capacity and the transport velocity. When there is a high loss of pressure, the carbon dioxide needs to be re-compressed. It will be clear that an optimum need to be found for the (initial) transport pressure and the design of the pipeline. The pressure loss can be influenced by for instance larger pipeline diameter, pipeline material (smoother wall will cause less friction), and temperature control.

During transport the combination of pressure and temperature should be chosen in such a way that carbon dioxide has a large density and is not in the gaseous phase. The lower pressure limit is set by the need to ensure that pipeline operation does not enter the two-phase region. The compressibility and density of CO_2 are the key properties that determine flow characteristics. Assuming that transport is done in a temperature window of zero to thirty degrees Celsius, it can be concluded from Figure I.1 that the pressure of the carbon dioxide should be at least 8 MPa. Allowing for some 2 to 3 MPa of pressure loss during transport, the initial pressure in the pipeline should be at least around 10 to 12 MPa depending on flow rate, transport distance and requirement pressure at injection facilities. In that way, a high density (800 kg/m^3) with a sufficient safety margin can be maintained. For offshore pipelines it may even be effective to start with pressures of up to 20 MPa. It should be noted that impurities might radically alter the compressibility of CO_2 resulting in reduced pipeline flow capacity relative to pure CO_2. The flow loss for a carbon dioxide stream with 10% nitrogen might be over 20% relative to pure CO_2 (Farris, 1983).