BERR | Department for Business Enterprise & Regulatory Reform

DEVELOPMENT OF A CO_2 TRANSPORT AND STORAGE NETWORK IN THE NORTH SEA

Report to the North Sea Basin Task Force

IN ASSOCIATION WITH

ELEMENT ENERGY
PÖYRY ENERGY
BRITISH GEOLOGICAL SURVEY

Caveat

Whilst the authors consider that the data and opinions contained in this report are sound, all parties must rely on their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. Key elements of this report - technologies, legislative environment, energy and CO_2 markets, are inherently uncertain, and a number of assumptions and approximations are used. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not necessarily reflect the views of the UK Government, Norwegian Government or the North Sea Basin Task Force.

Any comments or queries should be addressed to

Dr. Harsh Pershad
Harsh.Pershad@element-energy.co.uk
Tel: +44 (0)1223 227 532

or

Dr. Shane Slater
Shane.Slater@element-energy.co.uk
Tel: +44 (0)1223 227 764

About the Authors

The present study is a joint effort by a consortium led by Element Energy Ltd. with Pöyry Energy, and the British Geological Survey.

Element Energy Limited is a low carbon consultancy providing a full suite of services from strategic advice to engineering consultancy in the low carbon energy sector. Element Energy's strengths include techno-economic forecasting and delivering strategic advice to public and private sector clients (including government departments) on all opportunities connected to the low carbon economy. Element Energy has experience in the design of strategies for the coordinated deployment of low carbon infrastructure.

Pöyry Energy, the international consulting and engineering business within the Pöyry Group serving the energy sector. Our core areas of expertise are: Management Consulting, Hydropower, Renewable Energy, Power & Heat, and Oil & Gas. *Pöyry Energy Consulting* is Europe's leading energy consultancy, formed from the merger of ILEX Energy Consulting, Convergence Utility Consultants and the management consulting arms of Electrowatt-Ekono and Verbundplan. Pöyry Energy Consulting provides strategic, commercial, regulatory and policy advice to Europe's energy markets. Pöyry Energy's Oil & Gas business area has more than 300 multi-discipline oil and gas consultants servicing Europe, the Asia Pacific Region and the Middle East. Offices are located in Aberdeen (UK), Stavanger (Norway), Perth (Australia), and Kuala Lumpur (Malaysia), with personnel located worldwide.

The **British Geological Survey** (BGS) is the United Kingdom's premier centre for Earth Science information and expertise. BGS is responsible for advising the UK government on all aspects of geoscience as well as providing impartial geological advice to industry, academia and the public.

Version 1: prepared 10-07-07
Version 2: prepared 17-08-07
Version 3: prepared 10-09-07
Version 4: prepared 25-09-07
Version 5: prepared 06-11-07

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

The UK and Norwegian governments wish to examine the role that a pipeline infrastructure for carbon dioxide capture and storage (CCS) could play in reducing CO_2 emissions from both countries. The present study, commissioned by the UK Department of Business, Enterprise and Regulatory Reform (formerly the Department of Trade and Industry) on behalf of the UK, Norway and North Sea Basin Task Force, examines possible development pathways for a CCS pipeline infrastructure connecting large UK and Norwegian sources with appropriate sinks in the North Sea and reports on the implications for both countries.

To examine these issues, the project team developed a comprehensive database of onshore CO_2 sources and offshore CO_2 sinks. A list of CO_2 tolerant pipelines in the North sea was also developed and the potential for reuse of existing oil and gas infrastructure for CCS was explored.

Making use of the above databases, a CCS network model was developed; permitting relatively rapid assessment of network configurations Simple user input is required to define pipeline configurations over a set of development phases. It calculates sizing, capacity requirements and costs for CO_2 capture sources, new pipelines and booster stations, and offshore infrastructure, to provide estimates of capital and ongoing expenditure, CO_2 captured and abated. Lifetime cost of carbon abated is used to measure the efficiency of networks.

Sources

Depending on assumptions made on the rate of new build of fossil fuel-powered stations (and plant life extension if CCS is retro-fitted), between 200 and 350 Mt CO_2/year could be captured in the period 2030-2040 if capture facilities are fitted to all UK and Norwegian large onshore stationary sources (notably fossil-fuel fired power stations and some large industrial sources). The UK and Norway have sufficient gross storage capacity in their respective sectors to store this level of CO_2 output for many decades, though further validation of sinks is essential.

Large UK sources tend to be clustered, rather than evenly distributed across the UK. The highest concentration of UK CO_2 sources is found close to the Humber (in the region spanning East Midlands and South Yorkshire). The highest concentration of UK CO_2 sinks are close to these sources (i.e. gas fields and saline aquifers in the Southern North Sea).

Norwegian sources are fewer and the overall capacity is an order of magnitude lower than in the UK. The higher proportion of gas fired generators results in a higher average Norwegian capture cost per tonne of $CO_{2.}$

Norwegian sources are also geographically more dispersed, though nearly all are coastal. The potential for clustering of sources, is much less than in the UK.

Full details on the sources database, including existing and new sources and the cost modelling assumptions used, are given in chapter 3.

Sinks

The sink database contains 292 offshore geological storage sites, a mixture of oil fields, gas fields and aquifers. Though some sinks (particularly aquifers) are poorly characterised, the combined CO_2 storage potential in North Sea sinks should be sufficient to meet both UK and Norwegian needs for many decades.

There are concerns with the use each type of sinks. Saline aquifers have the largest storage potential but are less well characterised than oilfields and gas fields. The availabilities of oilfields and gas fields for CO_2 storage will depend on when oil and gas extraction terminates.

Matching the timing of sink availability to demand severely restricts the choices available for any CCS network that relies on the re-use of infrastructure. Thus, from a starting point of 292 sinks for which data are available, fewer than one in ten appear attractive options for CCS in any given five-year period from 2013-2037 (criteria for inclusion includes sink capacity, availability, level of risk, and EOR potential).

Reuse of existing infrastructure

Over the North Sea, several existing trunk pipelines appear technically suitable for carbon dioxide transport. These pipes are limited to transporting CO_2 at lower pressures than if new pipelines were built and could only be used assuming that the CO_2 transported is rigorously purified.

The suitability of any given pipeline can only be resolved by detailed examination with the pipeline owners/operators. The date that existing pipelines would become available for CO_2 transport depends on the close of production dates from the gas fields they service, which is difficult to forecast precisely.

The potential for reuse of offshore platforms depends on the intended duty of the platform, its service history, and is very sensitive to timing. The data required to properly assess reuse is platform specific and is commercially sensitive.

Any legislation which encourages rapid decommissioning of infrastructure when oil and gas production ceases would need to be reconsidered to encourage reuse for CCS.

As platforms reach the end of their service life the potential for reuse decreases. For this reason, this report makes an assumption that new platforms and wells will be required for CCS. This study contains a relatively refined cost model of offshore platforms. A significant differentiation obtains depending on EOR or Non-EOR use, with EOR platforms significantly more expensive to build and operate. The model also contains platform cost sensitivity as a function of water depth and reservoir depth.

Scenario based modelling

A CCS network model has been developed to allow relatively quick assessment and sensitivity analysis of CCS networks. User input is limited to describing how the network is connected at any one time. The model makes use of the datasets developed above, and includes infrastructure sizing and cost algorithms to predict the cost and performance of the network under study. Engineering costs estimates were taken from the IPCC's 2005 Special Report on Carbon Capture and Storage[i] and updated where additional data was available.

Due to the complexity and time dependent nature of the underlying data, automatic optimisation is not attempted, but the model lends itself to scenario based assessment of network efficiency. Two scenarios were modelled: a "centrally planned" and a "CO_2-Enhanced Oil Recovery-led" approach. The former is characterised by significant volumes of CO_2 being transported, and where the ultimate aim is achieving the lowest lifetime cost of carbon abated. The latter scenario is driven by a high oil price which supports demand for CO_2-EOR.

Conclusions from scenario based modelling

The price per tonne of CO_2 abated in the centrally planned scenario is £24/tonne (this includes capture costs, and commercial financing), representing a relatively cost effective carbon mitigation option.

Excluding capture, the cost for the remaining CCS infrastructure is £6/tonne. The cumulative cost over the five phase of development is £46 billion (including capture and commercial financing). A breakdown of capital costs shows that 78% is related to capture, 8% to platforms and wells, and 10% to pipelines. 37GW of generation capacity is connected by phase five.

In the EOR scenario, lifetime system cost of carbon abated increases to £35/tonne (including capture and commercial financing, but excluding revenues from EOR) and £18/tonne (excluding capture). The cumulative cost over the five phase of development is £29 billion (including capture and commercial financing).

With oil valued at £50/barrel the cumulative oil revenues for the system (by 2037) are £8billion. When these revenues are taken into account, the resulting cost of carbon is £24/tonne, indicating that oil must be valued above £50/bbl before EOR is predicted to be economically viable, relative to CO_2 capture with storage only. The analysis would suggest that EOR is unlikely to be an economic means of supporting Carbon Capture and Storage.

For the networks chosen, the efficiency (as measured by lifetime cost of carbon abated) tends to improve over time. This occurs because clustering of CO_2 sources leads to a gradual increase in the efficient use of infrastructure (particularly offshore platforms). Efficient networks are characterised by a large number of sinks connected to relatively few shoreline terminals and sinks.

Clustering achieves lifetime cost savings in part because foresight of future demand permits oversizing of the transport infrastructure to accommodate future capacity increases. Short-term commercial pressures may prevent the oversizing of transport infrastructure, leading to higher lifetime system cost. Regulatory oversight or Government investment would be required to ensure that short-term commercial pressures were balanced by long-term benefits.

Government will need to be mindful that the siting of capture plant in the near term should take into account the potential longer term benefits of clustering.

Sources that are inland are more exposed to planning risk due to the onshore transport infrastructure required. Government intervention may be required to reduce this risk and ensure inland CCS sources can be connected. In the context of the recent UK 2007 Planning White Paper, this could be in the form of a national statement of need for CO_2 pipelines.

Clustering has a much greater effect on network efficiency in the UK than in Norway. Its limited effect in Norway is due to the greater distance between sinks and their distribution near the coast. Combined with the higher cost of capture in Norway (with gas being the predominant fuel) this results in the cost of Norwegian CCS systems (per tonne abated) being higher than in the UK.

The centrally planned scenario makes use of a mixture of sinks (oil fields, gas fields and aquifers). There is sufficient sink capacity in each phase for the UK to connect its sources to its own sinks, and for Norway to do the same. Cost reductions could be achieved via joint use of sinks and this could act as an incentive for CO_2 to be transferred across national boundaries.

The EOR-led scenario is constrained during early phases by limited availability of suitable EOR sinks. This reduces the overall CO_2 capacity that can be transported. For the UK, with greater volumes of CO_2, access to Norwegian sinks during early developments, would be beneficial. By circa 2030, this is no longer a constraint.

Norway has a greater number of very large EOR fields than the UK. The conditions that favour EOR would support a (mainly Norwegian) demand for CO_2. This would support transport of CO_2 across boundaries for EOR. However, the proximity of southern North Sea countries (Germany and Denmark) to large, southerly Norwegian EOR fields (Ekofisk and Eldfisk) suggests these countries could provide a source of CO_2 that is competitive with UK.

To assist the exploitation of sinks for CCS, Government will need to play an active role to help gather data, prioritise and coordinate sink availability. Commercial constrains make it unlikely that this will happen independently. Without independent assessment, the potential for sub-optimal sink use, and higher lifetime cost of abatement, would result.

Offshore platforms are a significant cost element in the networks. Re-use of platforms could significantly reduce the cost of CCS networks (particularly in early phases of development), however an assessment of reuse potential is platform specific and requires commercially sensitive data. Government may need to appoint a regulator to ensure issues of competitiveness, confidentiality, and efficiency are properly balanced.

The environment within which CCS networks would develop is highly dynamic. Risk could be reduced through an oversight, regulatory or mandatory role taken by Government.

Oversizing of infrastructure to achieve lowest lifetime cost of carbon requires considerable assumptions about future supply and demand for CO_2. Government may need to insulate private operators from potential downsides of oversizing (due to reduced or delayed connection of CO_2).

While EOR may be required to encourage demand for CO_2, strong mechanisms will be required to support the supply/generation of CO_2. A compulsion based mechanism such as mandating CCS for new build (and retrofit) with clear deadlines, could operate similarly to the Large Combustion Plant Directive. This strong mechanism would also significantly reduce risk with regard to uncertainty when planning a CCS network.

For electricity generators, power plants fitted with CO_2 capture facilities and connected to a transport and storage network will be more expensive in terms of up-front and on-going costs, and in the absence of a high CO_2 price or other economic support, this gives them low positions in the merit curve. Regulation may be required to make sure plants fitted with capture equipment run at base-load, and not peak-load conditions.

2. BACKGROUND

The 2006 Energy Review[ii] , the Stern Review on the Economics of Climate Change[iii], and the recent Energy White Paper[iv] highlight the significant potential of Carbon dioxide Capture and Storage (CCS)i in meeting UK and global CO_2 emission reduction targets. A key component of CCS is an efficient and cost-effective CO_2 pipeline, or network of pipelines, connecting significant sources of CO_2 with potential CO_2 sinks.

The UK and Norway have set up the North Sea Basin Task Force (NSBTF), containing both government and industry representatives, to examine the issues surrounding the transport and storage of CO_2 beneath the North Sea. In addition Norway has already commissioned several studies that analyse the market and value chains for CCS which can help deliver the infrastructure needed to transport and store CO_2 below the North Sea.

In March 2007, the DTI commissioned a study on behalf of the North Sea Basin Taskforce with three core aims:

1. To assess how a physical pipeline infrastructure for the transportation of CO_2 could help enable carbon capture and storage in the North Sea. This would include an assessment of the possible re-use of existing pipelines.
2. To identify and evaluate the benefits and costs of such an infrastructure.
3. To identify barriers to developing such an infrastructure and what action would be required to overcome these.

To answer these questions, the approach taken in this report involves preparing inventories of CO_2 sources, CO_2 sinks, and existing pipeline infrastructure in the North Sea that may be appropriate to CCS. These datasets are used in a CO_2 network model. Early on it was identified that the temporal nature of these data would be significant, and the model would need to take account of which sources and sinks would be available in which time periods. Given the dynamic nature of the power and North Sea oil and gas industries, and the requirement to examine the growth of a CO_2 infrastructure, the model itself is dynamic, spanning over 25 years of network development, in five development phases. The approach allows the performance (efficiency) of earlier phases to be compared with the lifetime performance of the fully developed network. The first phase runs from 2013-2017; the final phase runs 2033-2037. By 2013, the EU's ETS is expected to enter its third phase. The long lead times associated with CCS planning and execution suggest that 2013 is a realistic start date for proposed UK and/or Norwegian CCS projects.

The model predicts the costs and benefits (e.g. CO_2 abated and enhanced oil recovered) for networks developed under a range of scenarios as agreed with the DTI. The scenarios suggest likely network development patterns, which can then be quantitatively examined.

3. CO_2 SOURCES

3.1. Sources Database

A 'sources database' has been created to provide key inputs to a network calculation. Data has been collected for over 95 distinct UK and up to 18 Norwegian current and estimated future stationary CO_2 sources, using public sources[v], commercial databases[vi] and in-house data[vii]. Key points about the sources database are:

- Covers power generation as well as industrial CO_2 sources (e.g. steel works, cement works and refineries).
- Includes all installations with relevant emission greater than 0.5 Mt/ year (80% of CO_2 emissions under EU ETS).
- Covers Norwegian as well as UK sources.
- For each source, contains latitude and longitude, CO_2 emissions, capacity, commissioning dates, expected retiral dates, fuel type, firing and capture technology, efficiency (pre- and post-capture), emission factor, load factors, and outputs.
- Assumptions and estimates are made for new build, including capacity margin (*ca.* 13%), and location (on existing sites that near the coast)
- Maximum and average annual CO_2 emissions (including capturable emissions) are calculated as a function of coal and gas prices.
- A judgement on the most likely capture technology for each source is made. This is used to calculate efficiency penalties, maximum CO_2 captured and abated, and the costs of CO_2 capture. In the case of retrofit, assumptions are made on plant life extension.
- Excludes offshore sources.
- Assumptions made on new build allow for a 1.5% growth in electricity demand.

3.2. High Level Mapping of Sources

The sources database was used to model CO_2 emissions (captured and abated) from each source in each year. This enabled identification and ranking of key sources for each phase. Two sets of CO_2 calculations were conducted, using DTI's central favouring coal and central favouring gas fuel price forecast data.

Figure 3.1 illustrates the locations and relative sizes of potential CO_2 sources in the UK in model Phase V (2033-2037), under two DTI's forecast fuel price scenarios. Key observations are:

- In the UK, a limited number of geographic clusters can be identified where multiple large sources are found in close proximity. The largest cluster falls near the Humber in a region spanning parts of the East Midlands and South Yorkshire. Other notable areas where CO_2 sources are in the same geographical region include South Wales, the Thames estuary, Teesside, Merseyside/North Wales, and around the Firth of Forth in Scotland.
- Since new sources are expected to be built largely on the same sites as existing sources, the same clusters appear important in all time periods of the sources database (i.e. 2013 up to 2037).
- Although absolute emissions vary, the same clusters are seen regardless of whether coal or gas is the dominant fuel for power generation.
- The same clusters may also be observed in each of the other phases. These clusters therefore represent attractive locations for nodes in any CO_2 pipeline network.

- The aggregate average annual *captureable* emissions of Norwegian sources is an order of magnitude lower than for the UK.
- Each of the top 40 UK sources is larger than any single Norwegian source.
- The largest CO_2 sources in Norway are all located on the coast. In the UK, large sources are found on the coast and inland. There are no large clusters of sources in Norway on the scale seen in the UK.

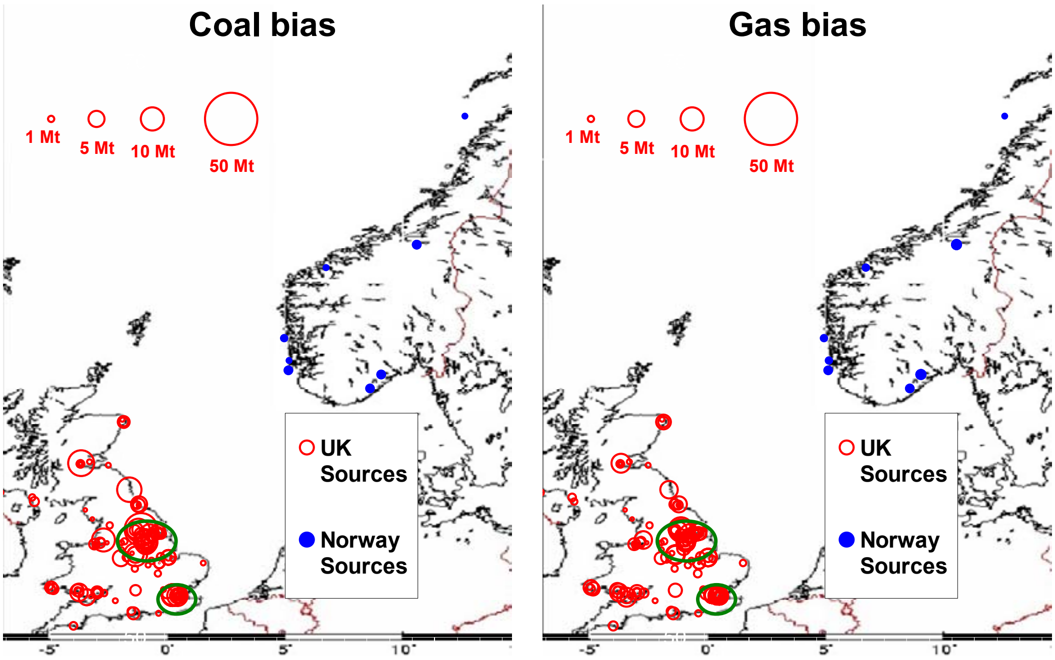


Figure 3-1 Maps of large stationary onshore UK and Norwegian CO_2 sources in the sources database. The CO_2 emission levels are modelled under fuel price regimes favouring coal (left) or gas (right). Bubbles areas indicate modelled average *capturable* annual Mt CO_2 emissions in period 2033-2037. Two clusters – in the East Midlands/South Yorkshire area, and around the Thames estuary are highlighted using green circles.

3.3. Estimating Costs of CO_2 capture for sources.

The model estimates the cost of capturing CO_2 through:

- Selecting the appropriate capture technology;
- Applying the relevant capital, fixed O&M and variable O&M costs to the relevant unit;
- Applying the Capital Cost Factor (CCF) to the capital costs; and
- Estimating the cost of the additional fuel used.

The model distinguish between sources that are gas fired, use pulverised coal or are IGCCs, and whether the carbon capture facilities will be retrofitted to existing units or included in the building of a new unit. The model then selects the appropriate capital and O&M costs, which are detailed in Table 3.1 below. The DBERR provided these costs, which are used in the MARKAL model. It is noted that market prices have increased significantly (up to 50%) since these data were obtained.

	Capital costs	O&M fixed	O&M variable	Capture efficiency
	£/kW	£/kW	p/kWh	
PF ASC with FGD no CCS	765	17	0.11	0%
New PF ASC with FGD and CCS	968	26	0.27	90%
Retrofit PF with FGD and CCS	601	24	0.25	90%
New IGCC no CCS	891	19	0.12	0%
New IGCC with CCS	1210	26	0.26	90%
New CCGT with CCS	690	12	0.17	90%
New CCGT no CCS	400	7	0.2	0%

Table 3.1 Ingoing CCS capture cost assumptions.

The information provided did not detail the costs of retrofitting carbon capture facilities to existing CCGT or IGCC units. It is assumed that these costs are the difference between the cost for such plant with and without the carbon capture facilities.

The capital costs are adjusted to include the cost of commercial financing. This is achieved through applying a Capital Cost Factor (CCF), which is the ratio of the amount required to achieve a certain level of return over a specific number of years to the initial amount. An example is the ratio of the sum of the repayments of a loan to the value of the original loan. As the rate of return and/or the number of years increases, so does the CCF. The CCF used in this report does not include the Interest During Construction (IDC - adding interest costs incurred during the Build Period, assuming the capital expenditure occurs evenly across the Build Period).

In principle, the capture, transport and storage process could have different build periods, payback periods and rates of return. The reason for different rates of return would include that the capture and storage aspects of the process will operate at a commercial rate while that for the Transport aspect may be regulated. While the model allows for this, for ease of interpretation the CCF of each part of the network is made equivalent (Table 3.2 below).

	Payback Period (years)	Rate of return	CCF
Capture	20	8%	2.04
Transport	20	8%	2.04
Storage	20	8%	2.04

Table 3.2 Capital Cost Factors (CCF) and relevant assumptions.

Units with carbon capture facilities use more fuel than those without such facilities to dispatch the same amount of power, as some energy is used to capture and compress CO_2. The cost of this additional fuel was determined through:

- Estimating the volume of fuel the unit with capture facilities uses;
- Determining the volume of fuel a unit without capture facilities would use to dispatch the same amount of electricity;
- Subtracting these amounts of fuel to determine the additional fuel used; and
- Multiplying the volume of additional fuel used by the cost of the fuel.

Further details of the calculation of these costs are detailed in section 9.1.

Key findings

Total emissions from large UK (onshore) sources are an order of magnitude larger than Norwegian (onshore) sources and are concentrated in a limited number of geographic clusters.

The largest cluster is located in the UK, near the Humber. The clustering is not expected to change significantly as a function of gas:coal fuel price ratio.

4. CO_2 SINKS

4.1. Potential Geological Storage Sites in the UK and Norway

The potential geological CO_2 storage sites identified in the UK and Norway are all offshore. For the purposes of the analysis, they are divided into three classes:

- Oil fields
- Gas fields
- Aquifers

Oil and gas fields, illustrated in Figure 4-1 below, are regarded as prime potential sites for CO_2 storage for the following reasons:

1. They have a proven seal which has retained buoyant fluids, in many cases for millions of years
2. A large body of knowledge about their geological and engineering characteristics has been acquired during the exploration and production phases of development.
3. In some cases there may be economic benefits to be gained from enhanced oil or gas recovery (EOR or EGR respectively) in conjunction with CO_2 storage. EOR is considered in the analysis. The potential for EGR is not considered further in this study but further details of the potential in the UK sector are given in Paterson[viii].

There is greater geological uncertainty over the potential to store CO_2 in saline aquifers. To date they have not been well characterised geologically because of their limited economic value. Nonetheless, they are regarded as having great potential because:

1. They are widely distributed, and occur in sedimentary basins that do not contain oil and gas and well as those that do
2. They commonly have very large pore volumes
3. They have been used successfully for natural gas storage onshore and CO_2 storage offshore, e.g. at the Sleipner field in the Norwegian sector

Further information about aquifers and their use for CO_2 storage may be found in Holloway *et al*. (2006a)[ix].

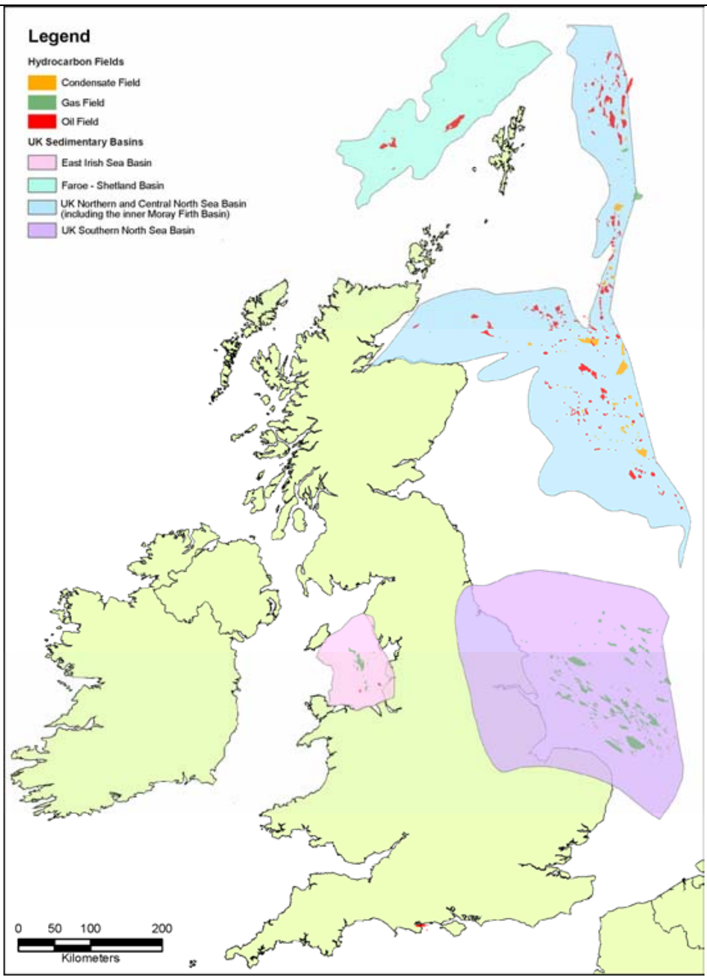


Figure 4-1 Map showing the location of offshore hydrocarbon fields and the major oil and gas-bearing sedimentary basins on the UK Continental Shelf.

4.1.1. Oil fields

Most of the UK's large offshore oil fields are in the Northern and Central North Sea Basin (Figure 4). However, there are three major fields (Clair, Foinaven and Schiehallion) in the Faroes-Shetland Basin, two (Douglas and Lennox) in the East Irish Sea Basin, and one (Beatrice) in the Inner Moray Firth Basin. There are also a number of onshore fields, most of which are very small. These are concentrated in the East Midlands and the Wessex Basin (in southern England). With the possible exception of Wytch Farm, which underlies Poole harbour, on the south coast of England (Figure 4-1) all the UK onshore oil fields are too small for significant CO_2 storage and they are not considered further in this study.

The Norwegian oil fields are all in either the Norwegian sector of the North Sea Basin (which is contiguous with the UK Central and Northern North Sea Basin shown in Figure 4-1) or the Norwegian Sea.

Two sets of CO_2 storage capacity figures have been collated for the oil fields:

1. *The mass of CO_2 that is likely to be stored as a result of enhanced oil recovery using CO_2.* For the UK, these figures were taken from ECL (2002, updated 2004)[x]. For Norway they were estimated from figures giving the amount of oil likely to be recovered by fully miscible CO_2-EOR from Norwegian fields in Mathiassen (2003)[xi]. In the base case analysis, the mass of CO_2 stored as a result of producing this additional oil was taken as 0.33 tonnes CO_2 per barrel of additional oil, following Tzimas et al. (2005)[xii]. Sensitivity to

this parameter was estimated later in the analysis. Note that not all the fields in either the UK or Norwegian sectors are regarded as technically suitable for miscible CO_2-EOR but a number of additional fields may be suitable for immiscible CO_2-flooding (Tzimas et al. 2005) [xii].

2. *The mass of CO_2 that could be stored in an oil field if CO_2 injection was continued until 100% of the pore volume occupied by the recoverable reserves was filled with CO_2.* These figures simply give a rough estimate of the maximum amount of CO_2 that could be stored in the fields regardless of economics. For the UK these figures are from Holloway & Baily (1996)[xiii] and for Norway from Boe *et al*. (2002) [xiv]. They were not used in the analysis except inasmuch as they indicate that the oil fields could take significantly more CO_2 than is required for EOR. This point is reiterated by Gassco (2006)[xv].

Estimated close of production (CoP) dates for the oil fields were obtained from DTI and NPD.

4.1.2. Gas fields

The UK onshore gas fields are all too small for significant CO_2 storage and are not considered further in this study. The UK offshore gas fields occur mainly in three areas: the East Irish Sea Basin, the Southern North Sea Basin and the Northern and Central North Sea Basin. The Norwegian gas fields considered in the study are all in either the Norwegian sector of the North Sea Basin or the Norwegian Sea.

The Central and Northern North Sea Basin and the Norwegian Sea contain both gas and gas condensate fields. Condensate is a term used for hydrocarbons that are gaseous under reservoir conditions of temperature and pressure but liquid under surface conditions. The Southern North Sea Basin and the East Irish Sea Basin fields have only low condensate yields and are commonly described as dry gas fields.

The methodology and algorithms for deriving potential storage capacity for gas fields are described in the Appendix (section 9.2.1).

4.1.3. Aquifers

There have not been any studies of the aquifer potential in the Norwegian and UK sectors of the North Sea that identify individual, well-characterised sites for CO_2 storage. In Norway, the potential storage formations have been characterised and their storage potential has been estimated (Boe *et al*. 2002)[xvi] but no individual storage structures have been identified. Consequently, for modelling purposes, it has been assumed that 25% of the storage potential in each formation could be accessed from a single injection point at the locations indicated for the individual storage formations in Boe *et al*. (2002)[xvi].

In the UK sector the potential storage formations have been characterised and their gross storage potential has been estimated (Holloway & Baily 1996)[xiii] but only a few individual potential storage sites have been identified in the Southern North Sea Basin (Holloway *et al*. 2006b)[xvii] and East Irish Sea Basin (Kirk 2006)[xviii]. The Southern North Sea sites are large anticlines in the Bunter Sandstone. Insufficient geological data was available to analyse the containment risk at these sites but such data as was available indicates that at least some of these structures are cut by faults and containment may be an issue. Because of the greater geological uncertainty over (a) the location of potential structures for aquifer storage and (b) whether they might leak, the locations and estimated storage capacities of the aquifer storage sites analysed in this report should be considered purely indicative.

4.2. Sinks Database

Using the above considerations, a sinks database was created for the purpose of network modelling. The database contains the following information on 292 potential UK and Norwegian CO_2 sinks:

- Location (longitude and latitude)
- CO_2 density reservoir conditions
- Formation volume factors
- Drive Mechanism
- CO_2 storage capacity
- Ultimately recoverable reserves
- Water depth
- Depth to crest
- Reservoir thickness
- Expected Close of Production Date (COP)
- Estimated EOR Start Date where applicable.
- Potential incremental oil yields from CO_2-Enhanced Oil Recovery.
- A qualitative measure of containment risk for UK aquifers was recorded based on faults identified on a very limited seismic reflection data set.

The database was used to understand the sink capacity and geography for the various types of sinks and their availability (based on close of production and EOR start dates). Using this information, suitable sinks were shortlisted for specific phases within each scenario (as described in Chapter 7.1 and the Appendix (Section 9.2.3). Combining sink capacity and EOR potential with infrastructure costs described later, the database was used to calculate storage costs (using the model built as described in Chapter 6).

4.2.1. Capacity

The total gross capacity of the 292 sinks in the sinks database is 35.5 Gt CO_2. The overall storage capacity is broken down as described in Table 4.2.1.

	UK	Norway
Storage capacity in gasfields (includes condensate fields)	5,982 Mt (75 fields)	4,440 Mt (42 fields)
Storage capacity in oilfields	4,225 Mt (74 fields).	4,768 Mt (36 fields)
Storage capacity in saline aquifers	14,466 Mt (32 sites)	1,681 Mt (33 sites)*
Incremental oil recoverable through EOR	2,006 MMSTB (37 EOR fields)	1,756 MMSTB (22 EOR fields)

Table 4.1 Aggregate gross CO_2 storage capacity and oil estimates for UK and Norwegian sinks in the sinks database. MMSTB = million metric standard barrels of oil.

There is considerable heterogeneity between sinks in terms of their CO_2 storage capacities, and in the case of CO_2-EOR, in incremental oil that can be produced. Figure 4-2 illustrates the geography and total capacity of the different sinks in the database (without consideration of timelines). For example, of the 292 sinks listed in the database, only 67 discrete sinks each have a total storage capacity of 100 Mt CO_2. Put another way, a large number of sinks that appear technically suitable for CO_2 storage may not be available as primary sinks as they are likely to be too small to be cost effective. This is discussed further in Appendix 9.2.3. However, once CCS infrastructure facilities are established, some satellite fields may prove useful.

With regards to geography, the largest UK storage potential is in aquifers and gas fields the Southern North Sea (i.e. off the east cost of England), although the storage potential in UK oilfields further north is nevertheless significant. Norwegian sinks in the sinks database are spread across the Northern and Central North Sea and in the Norwegian Sea. With a remit for the study on the potential for CCS infrastructure in the North Sea, sinks in the Barents Sea are excluded from study.

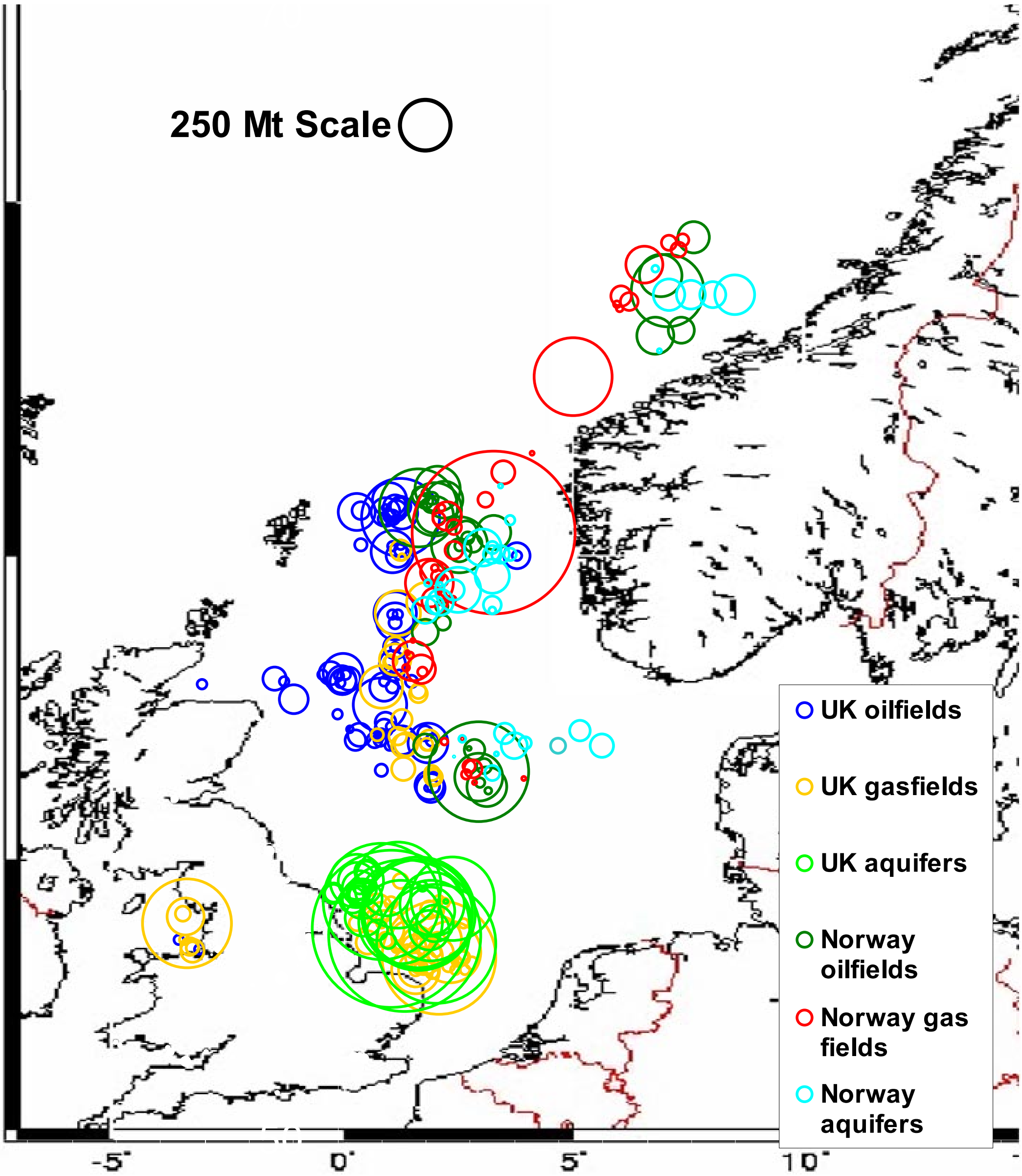


Figure 4-2 UK and Norwegian sink capacities in the sinks database. Bubble areas are proportional to predicted storage capacity for each sink. Sink colours refer to the type of sink (see legend).

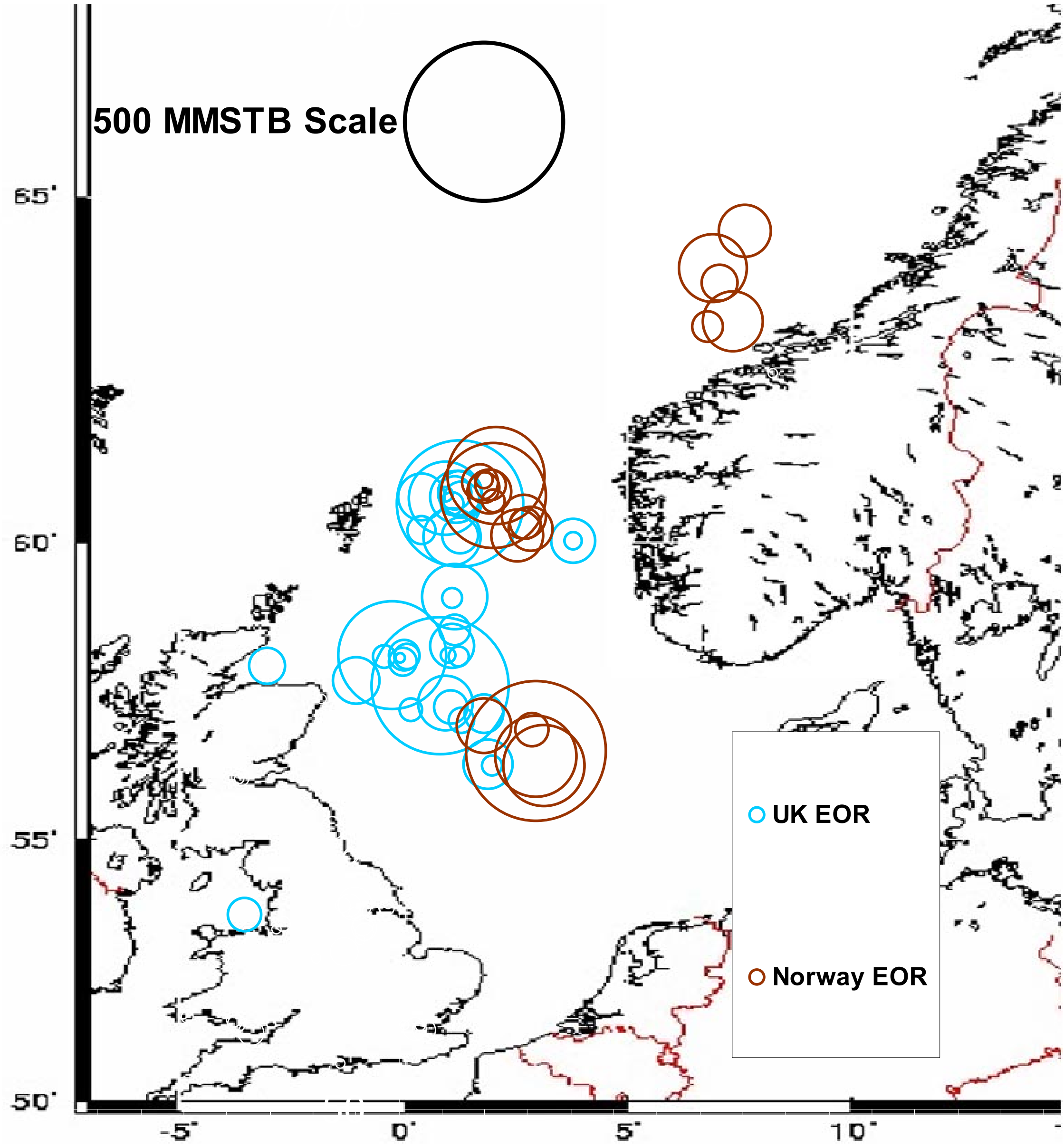


Figure 4-3 CO_2-EOR Opportunities for the UK (blue circles) and Norway (brown circles). Bubble areas are proportional to predicted incremental oil recovery. The scale marker (black circle) corresponds to 500 MMSTB. Data provided from ECL (2004).

For the UK sector, the total incremental oil in the sinks database is *ca.* 2 billion barrels (MSTB). The five largest UK EOR fields have a combined oil yield of 1.1 billion barrels, and a combined CO_2 storage capacity of 1.2 Gt. For the Norwegian sector, the total incremental oil is expected to be 1.8 billion barrels. The top five Norwegian EOR fields have a combined incremental oil yield of 1.1 billion barrels, and a combined CO_2 storage capacity of 1.8 Gt. Clearly both storage capacities and incremental oil yields are substantial. Therefore, and as discussed in a number of papers, it behoves us to examine to what extent inclusion of EOR within any CCS network may help to reduce networks costs.

4.2.2. Timeline of availability

The following assumptions were made with respect to when specific sinks become available for CO_2 storage.

- Gas fields - assumed to be available for CO_2 injection from the close of production (COP) date. Ideally CO_2 injection begins when gas production ceases.
- Oil fields used for EOR – available from literature-estimated EOR start dates, or where data not available, around three years prior to COP (timelines based on ECL, DTI and NPD data are illustrated in Section 9.2.2).
- Oil fields used for pure CO_2 storage only – assumed to be available for CO_2 injection from the close of production (COP) date. Ideally CO_2 injection begins when oil production ceases.
- Saline aquifers – assumed to be available in each phase.

Key Findings on CO_2 sinks:

- A sinks database has been created which contains location, depth, storage capacity, close of production (COP) dates on 292 different sinks (181 UK sinks and 111 Norwegian sinks), covering gas fields, condensate fields, oil fields and saline aquifers.
- In the case of oilfields which can be used for EOR, the expected oil reserves and EOR start dates are also included.
- The COP dates are highly uncertain and depend on market conditions (notably oil price and technology developments).
- Sufficient theoretical storage capacity exists to meet likely UK and Norwegian demand for several decades.
- If re-use of existing infrastructure is considered a high priority, then the availability of gas fields and oilfields to store CO_2, and especially in the case of EOR, is highly time dependent, as many North Sea fields are reaching the ends of their lives.
- The actual CO_2 storage potentials of saline aquifers are poorly defined.

5. SINK INFRASTRUCTURE

5.1. Offshore Injection Scenarios

The potential for platform and well infrastructure re-use is highly sink dependent, as summarised in Table 5.1[xix]. Schematics corresponding to each scenario are provided in the Appendix (9.2.4).

Sink Scenario	Adaptation of existing platform to host injection wells?	Modification of existing wells for CO_2 injection?
CO_2 storage in a depleted gasfield	Estimated at 50% possibility	Estimated at 50% possibility
CO_2 storage in a depleted oilfield	Estimated at 50% possibility	Estimated at 50% possibility
EOR at an oilfield followed by CO_2 storage	Estimated at 50% possibility	Production wells remain in use. New subsea injection template and new wells required (but 50% opportunity to re-use water injection wells if available).
CO_2 storage in a saline aquifer	New platforms required.	New wells required.

Table 5.1 Suitability estimated for existing platform and wells. N.B. Network costs in later chapters assume new infrastructure is used.

5.2. Offshore Facilities for CO_2 Injection

5.2.1. Injection Wells Configuration

The number and configuration of CO_2 injection wells are heavily dependent on the reservoir geometry and physical characteristics such as faulting, porosity and permeability, which will vary widely from field to field. Therefore in a study such as this, only broad generalisations can be made.

In the study model, the number of wells required for each sink is determined by the nominated sink injection rate (a function of CO_2 supply and the expected operating lifetime of each sink), and an average injection rate per well of 1.25 Mt CO_2 per year. Where resilience is required in a network, a more cautious assumption of 0.75 Mt CO_2 per year per well could be modelled.[xx] The latter might necessitate more platforms, and therefore potentially more sinks. The resulting cost function could be explored in a sensitivity analysis.

In some cases, existing wells may be re-used, with little costs except above those required for wellbore and completion integrity assessment and possible remedial work. However it is difficult to quantify how many wells may be re-used for any specific sink, although industry experts consider 50% re-use would be a good starting approximation[xxi]. The network cost dependence to platform or well re-use can be explored in a sensitivity analysis as further data becomes available.

5.2.2. Facility Functional Requirements

At each offshore sink location a facility is required to distribute the CO_2 arriving by pipeline between the wellheads of the injection wells. In its simplest form, CO_2 arrives at a suitable pressure for injection and only one or two wells are involved. The facility could then be a subsea wellhead (i.e. located on the seafloor) with valving to control fluid distribution. Such technology is commonplace in oil and gas production, and this is the configuration adopted in the Snøhvit CO_2 injection project.

If the storage reservoir is more than around 1,000 metres below seabed, and existing pipeline infrastructure is used (with its attendant pressure limitations), the CO_2 arrival pressure will likely be insufficient for injection without pressure boosting at the offshore location. On the basis of current proven technology, such pressure boosting requires conventional pumps which must be located on a fixed platform similar to that used for oil and gas production. However, if new pipelines are used then CO_2 can be delivered to the injection location at significantly higher pressures, which will obviate the need for offshore boosting for all but the few deepest reservoirs. In this case the offshore platform can be much simplified and would be able to operate unmanned. This assumption has been adopted for the economic modelling of offshore pipelines and platforms in the Study.

There are associated benefits in locating the CO_2 injection wellheads on a fixed platform above the waterline, in terms of ease of access downhole for well workover (maintenance and repair). This factor is likely to drive any development involving more than 3 – 4 wells (3.75-5 Mt CO_2/year) towards a fixed platform rather than subsea.

The fixed facility functional requirements are likely to include:

- Wellheads and manifolding
- Well workover capability
- Temporary accommodation (facility would not normally be manned)
- Crane
- Helideck

5.2.3. Suitability of Existing Platforms

For the scenarios of CO_2 injection into depleted oil or gas fields, there are existing production platforms located over most fields which could potentially be adapted to provide the functional elements listed above. Existing gas compression and oil pumping systems will not be suitable for boosting of CO_2 if this is contemplated, and therefore this capability will have to be added in each case, ideally in the form of a module which can be lifted onto the existing structure. The ability of a given platform to accommodate such a module can only be assessed on a case-by-case basis. As with re-use of pipelines, there is also the uncertainty of residual life of the support structure of any platform, given that some are a year or two old and others are approaching 40 years old.

For the scenario of CO_2 injection at an existing oilfield for EOR, there is the added complexity of continued hydrocarbon production, and thus the issue of changes to the process stream composition due to the recycled CO_2. The existing piping and equipment may not be metallurgically suitable for the revised stream, and may need to be replaced in whole or in part. New equipment will also be required to separate and recycle to CO_2. Previous studies[xxii] have shown that in some circumstances it may be more economic to install a new injection platform adjacent to the existing production platform.

Another uncertainty is the ability of an existing platform to accommodate newly drilled CO_2 injection wells, or to offer existing production or water injection wells which can be adapted for CO_2 injection. This is a complex issue and the study has adopted a simplified assumption of

50% new / 50% re-use of existing wells. If a platform cannot accommodate new wells then these can be drilled as subsea wells a few kilometres from the platform and connected by a short pipeline, as illustrated in the schematics in the Appendix.

For the scenario of CO_2 storage in a saline aquifer, there may not be a suitable existing platform in the vicinity of the injection point. In this case a new platform would be required.

5.2.4. Indicative Injection Platform Costs

Order-of-magnitude costs have been developed for new injection platforms, covering a range of well numbers and a range of water depths (40 to 160 metres). The costs are summarised in
Table 5.2 and are prepared on the following basis:

- Current North Sea market conditions for new platform developments
- Drilling and completion costs of injection wells are excluded
- Costs are unrisked (i.e. no contingency allowance)

	With EOR	**Without EOR**
Number of wells **Injection capacity**	**20** *25 Mt CO_2/year*	**20** *25 Mt CO_2/year*
< 100m water depth	£140m	£ 40m
> 100m water depth	£280m	£ 75m

Table 5.2 Estimates of new platform costs as a function of depth. For simplicity, only a single size platform is chosen, corresponding to 20 well injection (at 1.25 Mt CO_2/year/well). The cost of drilling wells is not included in this table.

The costs of modifying existing platforms for re-use are expected to vary widely depending on the extent of modifications required, and the capacity of the existing platform to accommodate them. For the case of adding boosting capacity to an existing platform on a depleted field (i.e. EOR not envisaged) which has space to take a new module of around 300 – 500 tonnes, this is broadly analogous to North Sea practice whereby a platform acts as host for a new subsea well “tieback”. The current cost of such a modification is typically around £50 million. For the case of CO_2 injection associated with EOR, a study undertaken for the DTI by Genesis (2002)[xxii] covering two specific fields indicated a wide variability of estimated modification cost, between £21 million and £176 million, which in current market conditions would equate to £30 million - £250 million. A suitable median cost which could be generically applied in a study such as this would be £150 million.

5.3. Onshore Terminals

The gathering of CO_2 from various onshore sources is assumed to focus on the locations of existing landfall reception terminals for gas and oil pipelines arriving at the coast. These locations are logical sites for the CO_2 export terminals, due to the presence of facilities and infrastructure and the ability to connect to the existing offshore pipeline network. The CO_2 export facility would comprise a combination of compression and pumping to boost the CO_2 stream to the pipeline operating pressure. For new export pipelines this pressure will be within the range 200 – 300 bar, however if existing oil or gas pipelines are used, these are limited in design pressure to between 90 and 180 bar depending on age and original duty.

The CO_2 export facility would be sited either within the existing terminal or adjacent to it, to allow utilities and access to be shared.

5.4. Offshore Pipelines for CO_2 Transportation

CO_2 has been transported by pipeline for over 30 years, primarily onshore in the USA as part of EOR projects, where over 2,500km of pipelines are in service. To date no offshore CO_2 pipelines have been installed, but this is due to a lack of demand rather than any technical barrier. An 8-inch offshore CO_2 pipeline is currently under development in Norway as part of the Snøhvit project.

CO_2 is most efficiently transported by pipeline in the dense phase (above 60 – 80 bar pressure, depending on temperature and impurity levels). In this phase CO_2 has the density of a liquid but the viscosity and compressibility of a gas. A parametric hydraulic analysis has been performed to illustrate the relationship between pipeline internal diameter and capacity for a range of lengths and operating pressures, based on maintaining the fluid arrival pressure at the offshore sink above 85 bar. The results are presented graphically in Appendix 11.4.

There is an extensive network of oil and gas pipelines in both the UK and Norwegian sectors of the North Sea, which presents a significant opportunity for re-use as part of a North Sea - based CO_2 storage infrastructure[xxiii]. In principle these existing pipelines, the vast majority of which are carbon steel, are metallurgically suitable to carry CO_2 provided that the moisture content is maintained at a sufficiently low level, approximately 500 ppm. The main limitation of the existing lines is design pressure, which varies between 90 and 180 bar. The effect of this limitation is to reduce transportation capacity compared to a purpose-built new line, which would likely be designed for a pressure of between 200 and 300 bar. However, most of the major existing North Sea trunklines are relatively large diameter and still offer significant CO_2 capacity. 28 pipelines identified in the UK sector appear to have a capacity in the range 10-50 Mt CO_2/year.

The second uncertainty regarding existing lines is remaining service life. Many North Sea pipelines, particularly in the Southern basin of the UK sector, have been in operation for between 20 and 40 years. Remaining service life can only be assessed on a case-by-case basis, taking into account internal corrosion, and the remaining fatigue life.

Table 9.1and Table 9.2 in the Appendix summarise the details of the principal existing North Sea pipelines (trunklines) which connect to a landfall point in either UK or Norway respectively. These would be primary candidates for re-use for CO_2 transportation. There are in addition many smaller infield and inter-field pipelines which connect into these trunklines offshore from various contributing fields, which could also be considered for CO_2 transportation if the connected fields are selected as storage sinks. Note that current decommissioning practice for North Sea pipelines is to purge the hydrocarbon contents, fill them with inhibited seawater and leave them in place.

6. DEVELOPMENT OF A CCS NETWORK MODEL

A CCS network model has been developed using the sources, sinks and infrastructure datasets described previously. The purpose of the model is to allow the quick assessment of a large range of networks, identify constraints and help develop optimum configurations. The model contains:

1. *Set of assumptions*
   Including current and future energy prices, coal or gas led energy generation, length of each phase, depreciation rates.

2. *Source and sink datasets*
   A comprehensive list of CCS sources and sinks over the period to 2040. Each point (or node) is given a unique numerical identifier in the model.

3. *Connectivity tables*
   The user specifies the layout of the network by inputting a list of paired numbers, identifying the nodes to be joined (via pipelines). Nodes may be onshore CO_2 sources, intermediate collection points, shoreline terminals, or offshore sinks. There are five tables, one for each phase of network development.

4. *CO_2 flow rate calculator*
   The core of the model calculates the CO_2 flow rate through each node in the network, balancing flow rates from sources through to sinks.

5. *Infrastructure sizing and cost algorithms*
   Based on the CO_2 flow rate, the model estimates capacity requirements for pipelines, booster stations, and the number of offshore platforms and injection wells required at each sink. Based on these size estimates, cost models give capex and cost estimates.

6. *Cost and CO_2 outputs*
   Annual capex and opex for CO_2 capture, pipelines, offshore platforms, injection wells, surveying and monitoring; annual CO_2 captured and abated; lifetime network cost efficiency as measured by £/Tonne CO_2 abated.

The lists of paired numbers in the connectivity tables are the only user input required. Due to the temporal aspect of the datasets and of the network itself, the model checks if:

- A chosen source is unavailable at any time while connected to a network
- A sink is unavailable at the required time, or the CO_2 flow rate required at the sink exceed the maximum injection rate, or the sink capacity is reached.

While some guidance is generated on the most proximate shoreline terminals and sinks, the dynamic nature of the network and underlying datasets makes automated cost optimisation very challenging: none is attempted. Instead, the simple data entry method means complex networks can be analysed quickly. Networks may be rerouted quickly should problems arise, and a variety of networks can be analysed to identify optimal configurations.

7. NORTH SEA CCS NETWORK MODELS

7.1. Specification of Networks

The model described above allows a quantitative examination of the volumes of CO_2 captured and abatement and costs for any CCS network specified. A scenario-based approach is used to illustrated the operation of the model and provide quantitative outputs from this study.

In consultation with DTI, the following issues were highlighted for examination:

- Networks which include the potential for joint infrastructure development between the UK and Norway.
- Sensitivity to the use of different types of sinks, for example using only EOR sinks, or not using aquifers (the suitability of which for CCS is imperfectly understood at present).
- Network costs and benefits associated with increased flexibility/resilience.
- Comparison of a “centrally planned” CCS pipeline network against a “project by project approach”. The latter do not oversize any infrastructure to account for future increased demand in capacity, while the centrally planned systems do allow for this.
- Implications of mostly coal-based or mostly gas-based power generation (as a result of fuel price) on CCS networks.

In response to these requirements, and to illustrate the use of the model, two pipeline network scenarios are developed. These respond to different market and regulatory environments and result in different source/sink/pipeline combinations.

Considerations/ Assumptions	**Centrally Planned Network**	**Market Driven by CO_2 for EOR**
Level of Government action	High	Low
Main Driver(s)	Maximum cost effective CO_2 abatement.	Enhanced oil revenues
Degree of foresight	High	Low - ‘project-by-project’ approach.
Assumed oil price	$50/bbl	$50-$100/bbl
Implicit carbon price	High	Low
Choice of sources	Main priority is highest CO_2 abatement at lowest lifetime cost for the whole network. Diversity encouraged.	Sources nearest EOR opportunities favoured.
Choice of sinks	Lowest risk and cheapest sinks encouraged. Diversity encouraged.	EOR-only sinks.

Table 7.1 – Assumptions used for the two scenarios.

7.2. Centrally planned network

Reflecting an ingoing assumption that CCS will be a key carbon reduction technology, this network deploys rapidly and ultimately contains a large number of sources. Where possible, best use is made of offshore infrastructure, which leads to clustering of sources onshore, limiting the number of shoreline terminals and sinks used. Available sinks are a mixture of oil fields, gas fields and aquifers.

Network development begins with the connection of two UK and one Norwegian demonstration projects. These sources have been chosen by the project team for illustration purposes only and do not imply a preference over other planned CCS demonstration projects that have been announced.

The sources in the central development network are predominantly from the eastern side of the UK, with clusters around Teeside, the Humber, and East London. Onshore pipe lengths are kept short to limit costs, however, sources inland are included. This reflects the role government may have to adopt (in a centrally planned scenario) to achieve planning permission for large-scale onshore pipeline networks. In Norway, all sources are on the coast.

A complete list of sources and sinks connected in each phase, is given in the appendix.

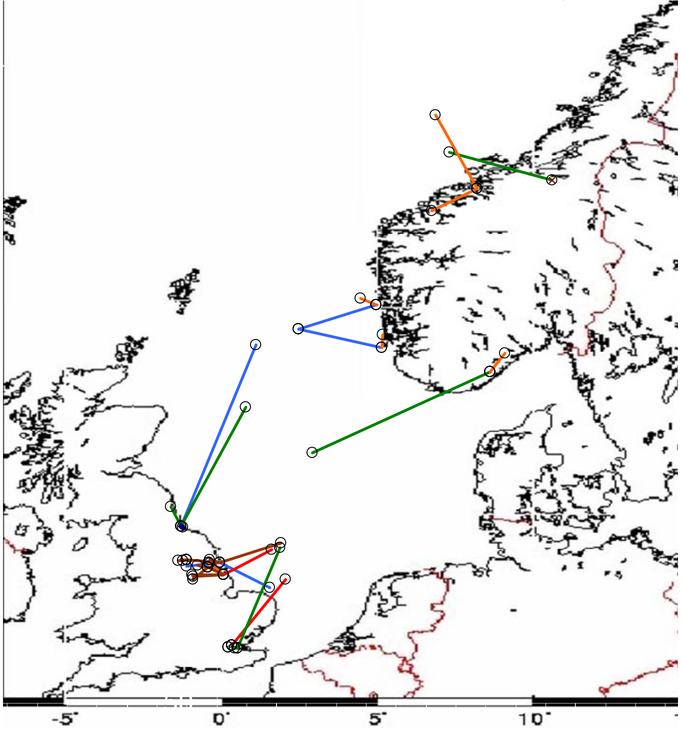


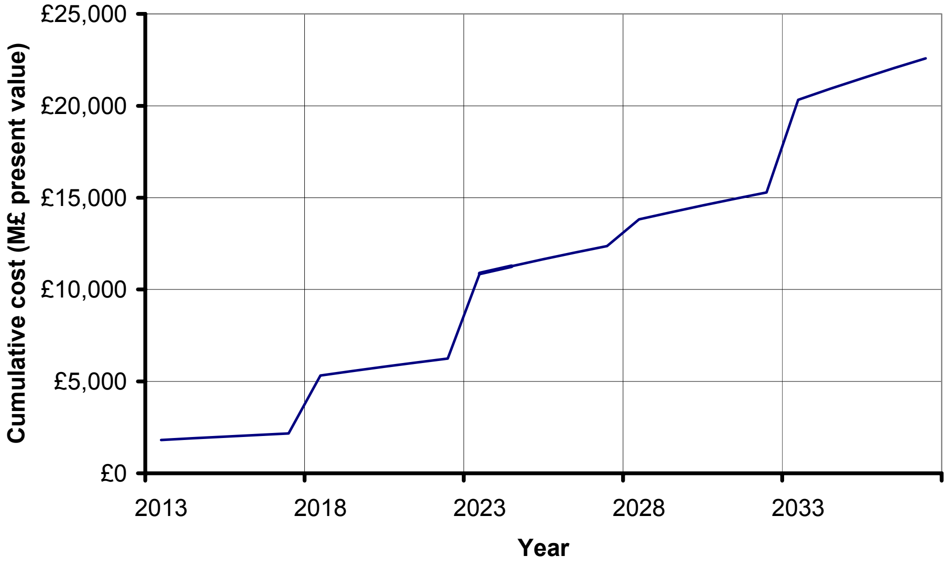
Figure 7-1. Pipeline configuration at Phase V (central plan scenario). Pipelines are colour coded according to the year in which they were laid: Blue (laid in Phase I), red (Phase II), green (Phase III), orange (Phase IV) and brown (Phase V).

The three main onshore clusters in the UK may be observed: at Teeside, the Humber, and Thames estuary. While sources outside of these areas should not be excluded, clustering does make more efficient use of shoreline terminals and offshore infrastructure.

The availability of oil field, gas field or aquifer sinks means suitably large sinks may be accessed as necessary at each phase of development, separately in both the UK and Norwegian sectors. This factor, combined with the proximity (i.e. lower cost) of nationally owned sinks, means there is little driver for the trading of CO_2 between the two countries.

Sinks generally do not fill up over the time period under study. However, as source clusters form, the CO_2 injection rate to some sinks rises above the maximum that is commercially achievable. In these circumstances, new sinks are required, which incur new pipeline, platform and injection well costs. The availability of high capacity sinks early in network development reduces the requirements (in later phases) to connect new sinks to shoreline terminals (in later phases the CO_2 throughput at terminals increases substantially).

The network makes use of a variety of gas fields, oil fields and aquifers. In particular, the aquifers used tend to have the largest capacities of all sinks and become increasingly important as clustering of sources increases. This makes the network sensitive to the use of aquifers. If aquifers were to be excluded from consideration, this would reduce the quantity of CO_2 that could be transported, particularly in early phases. It would also increase cost, as the aquifers tend to be larger capacity sinks.



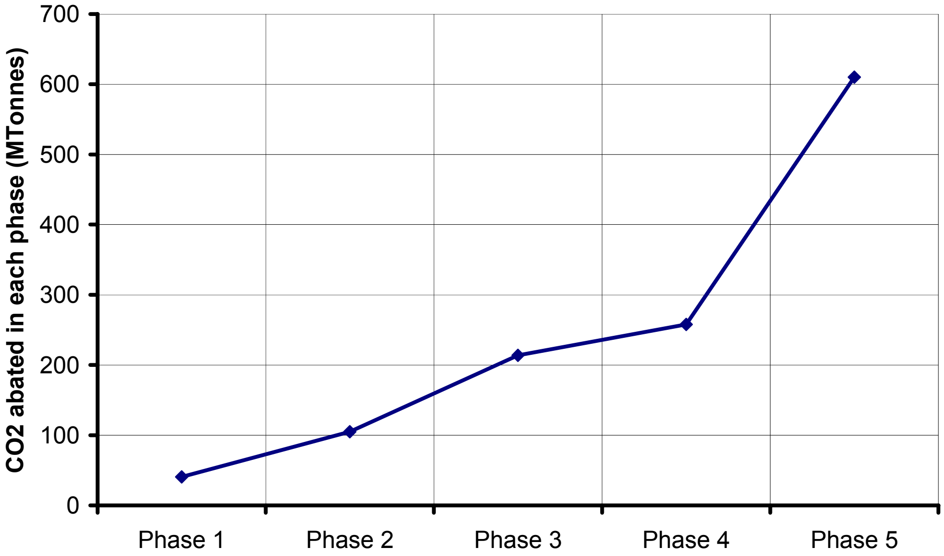


Figure 7-2 Volume of CO_2 abated (per phase) and costs incurred for the centrally planned network containing UK and Norwegian sources and sinks. Costs do not include commercial financing. CO_2 figures are total volumes abated in each phase, and are not cumulative.

The graphs above show volumes of CO_2 transported and costs incurred through each phase. To maintain a distinction between capital and operational costs, capital expenditure on new infrastructure is shown to occur at the start of the phase where it becomes operational. By the end of phase 5, over 120Mt CO_2 per annum is being transported from the UK by the network, representing 37GW (output post capture) of UK electricity generation capacity.

Variable	units	Without capture costs	With capture costs
Total CO2 abated (30 years)	Mtonnes	1,889	1,889
Present Value System Cost	£M	5,664	22,574
Cost (inc. commercial financing)	£M	11,539	45,984
Cost per tonne abated	£/tonne	3	12
Cost per tonne abated (inc. financing)	£/tonne	6	24

Table 7.2 Centrally Planned Network Capacity and Costs

The efficiency of the network is measured by its lifetime cost per tonne of CO_2 abated, as shown in Table 7.2. A treasury discount rate of 3.5% is used to give present value system costs. System costs that account for the cost of commercial loans (8% over 20 years) are also shown. The results indicate a lifetime cost of carbon abated at £12/tonne (£24/tonne inc. financing). The table also shows that over 75% of overall system cost is related to capture (both capital and operational expenditure).

	PHASE 1	PHASE 2	PHASE 3	PHASE 4	PHASE 5
Capital costs	**M£**	**M£**	**M£**	**M£**	**M£**
Capture costs	£749.9	£2,575.1	£5,176.4	£1,060.1	£9,328.3
Pipeline capex	£594.6	£526.0	£713.0	£536.9	£190.0
Booster station capex	£29.2	£26.7	£87.9	£42.8	£430.7
Survey costs	£4.9	£0.0	£3.7	£4.9	£1.2
Platform capex	£230.0	£150.0	£190.0	£300.0	£150.0
Drilling station capex	£172.9	£389.1	£339.5	£30.1	£0.1

Table 7.3 Centrally Planned Network Costs Breakdown

The capital cost components of this system are shown in Table 7.3 (cap. ex. only, not depreciated, not inclusive of financing). Over the five phases, circa 78% of capital costs are related to capture, 8% to platforms and wells, and 10% to pipelines. However this proportion does change between phases. In Phase 1 and Phase 4, just 42% and 53% respectively of capital costs are capture-related. In these phases, new offshore infrastructure is required and this reduces the component related to capture. Other phases make more efficient use of this infrastructure, with the result that the component of capital expenditure related to capture is much higher in those phases.

In this scenario, there is no interaction between UK and Norwegian networks, and this permits their independent analysis. The UK-only network cost of carbon is £112/tonne (inc. financing) which is lower than the Norwegian figure. There are a number of reasons for this difference. In the UK, clustering of sources results in significant network performance improvement. As the network develops and clustering increases, the greater volume of CO_2 increases the effectiveness with which the offshore infrastructure is used. For example, the lifetime cost of the Teesside facility connected in phase 1 is £33/tonne CO_2 (assuming no further network developments). This is typical of sources connected during early phases. The tendency is that lifetime system cost of carbon improves as connectivity and clustering increases.

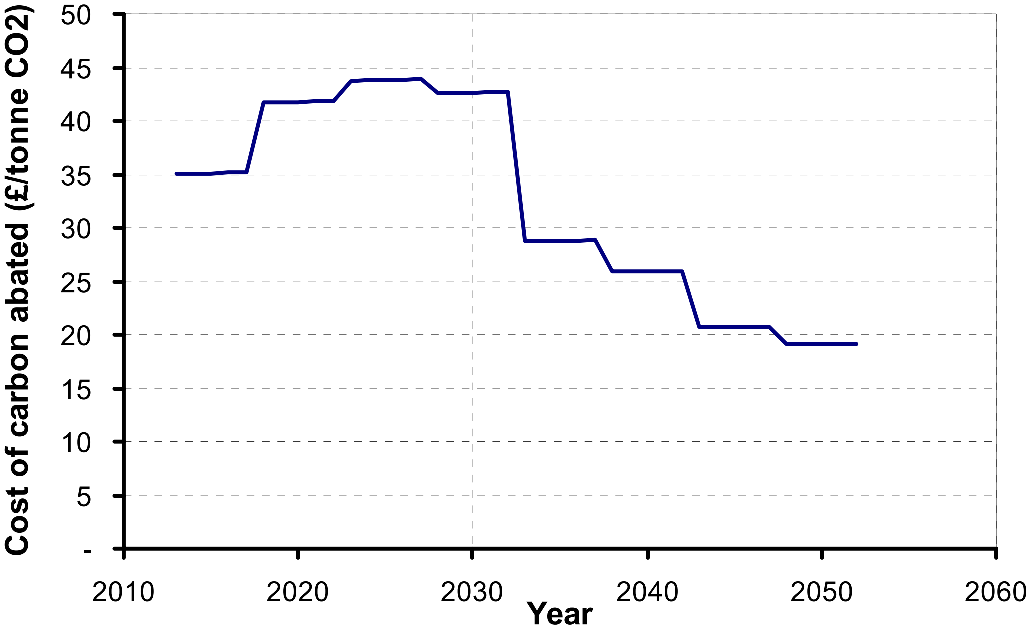


Figure 7-3: Cost of carbon abated per year, over the period of network development. In order to highlight more efficient use of infrastructure over time, costs are not depreciated

Due to limitations in geography, this form of clustering is not possible with Norwegian sources and as a result the performance improvement is not seen to the same degree.
Also capture costs are greater - Norwegian generation is mainly gas-led which has higher costs per tonne of CO_2. Finally, Norwegian sinks tend to be deeper below the water than UK sinks, this increases the cost of the platform required for Norwegian sinks.

7.3. EOR led scenario

In this scenario, higher oil prices support a demand for CO_2 for enhanced oil recovery from North Sea oil wells. Within this context, it is assumed that low cost CO_2 can be provided by capture plant, that CO_2-EOR is used in preference to other EOR technologies, and that EOR would still be cheaper than alternative oil production sources.

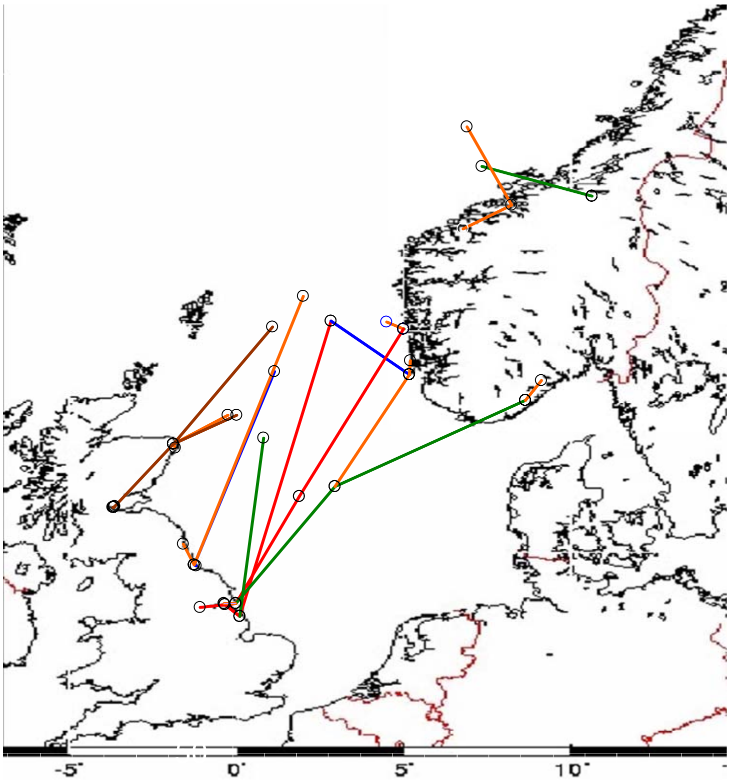
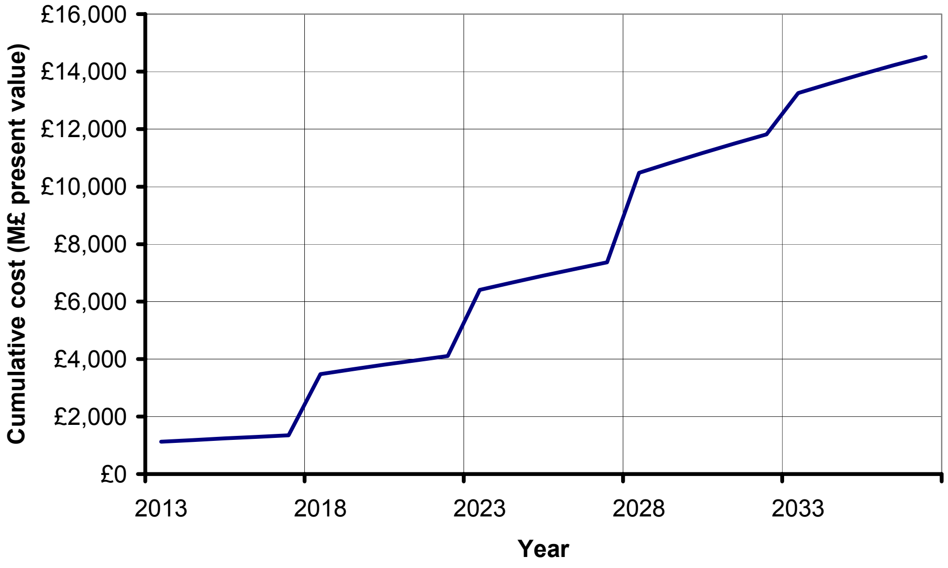


Figure 7-4: Network configuration at Phase V (EOR scenario). Pipelines are colour coded according to the year in which they were laid: Blue (laid in Phase I), red (Phase II), green (Phase III), orange (Phase IV) and brown (Phase V).

A main distinction from the central scenario is that if only EOR sinks are used, the choice of sinks is much smaller. This limits the overall sink injection capacity. There are few large EOR sinks in Phase I or Phase II (in the UK sector, the largest EOR sink is expected to cease production before the start of a CO_2-EOR network). EOR potential grows significantly in Phase III (2023-2027). Assuming these very large sinks are connected, EOR sinks are sufficient for large networks by phase V (2033-2037).

The EOR scenario is expected to be driven project-by-project, with less sharing of pipelines or sinks than in the centrally planned scenario. Also the storage capacity of individual EOR sinks (particularly those in early phases) is lower than many of the sinks (particularly aquifers) used in the central network, EOR sinks connected in early phases reach capacity quickly and more sinks have to be connected to meet the demand. The increased number of sinks in the network (per tonne of CO_2 transported) increases the cost of the network.

During early phases, UK and Norway may use their own sinks, but in later networks there is benefit from connecting UK sources to Norwegian sinks. This benefits the UK – many Norwegian EOR sinks are very large and can accommodate significant volumes of CO_2, and benefits Norway – EOR revenues may be generated without Norway incurring the (relatively higher) cost of CO_2 capture and transmission offshore.



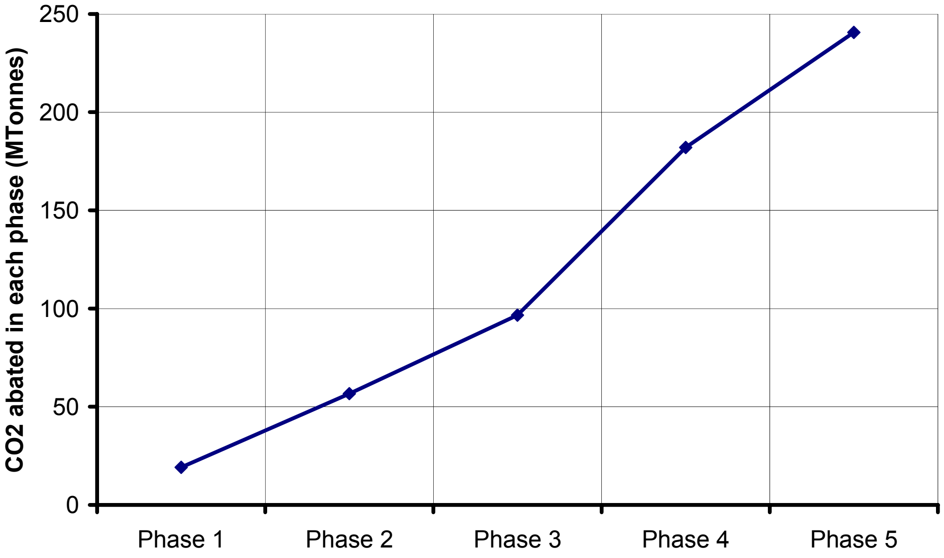


Figure 7-5: Volume of CO_2 abated (per phase) and costs incurred for the EOR led network, with UK and Norwegian sources and sinks.

The graphs above show volumes of CO_2 transported and costs incurred through each phase. When compared to the centrally planned scenario, lower volumes of CO_2 are transported and abated.

Variable	units	Without capture costs	With capture costs
Total CO2 abated (30 years)	Mtonnes	836	836
Present Value System Cost	£M	7,572	14,518
Cost (inc. commercial financing)	£M	15,425	29,573
Cost per tonne abated	£/tonne	9	17
Cost per tonne abated (inc. financing)	£/tonne	18	35

Table 7.4 EOR Network capacity and costs. Figures exclude revenue from EOR.

The lifetime cost of CO_2 abated in the EOR network is estimated at £17/tonne CO_2 (£35/tonne inc. financing). This is higher than in the central, mainly due to the greater number of sinks and the longer overall pipeline length required. The cost model for platforms differentiates between EOR (£140-£280M, depending on water depth) and non-EOR (£40-75M depending on water depth). Also EOR platforms have an annual running cost of 10% of cap. ex., while the figure for non-EOR platforms is 2%. As with the centrally planned network, Norwegian system costs are higher due to higher average capture costs and deeper sinks. The proportion of system costs related to capture is lower in this scenario, again due to the greater amount of offshore infrastructure required and the capital and operational expenditures required.

	PHASE 1	**PHASE 2**	**PHASE 3**	**PHASE 4**	**PHASE 5**
Capital costs	**M£**	**M£**	**M£**	**M£**	**M£**
Capture costs	£377.0	£962.8	£938.2	£3,135.2	£1,645.1
Pipeline capex	£326.6	£938.7	£1,095.4	£825.5	£265.1
Booster station capex	£20.4	£12.9	£17.5	£80.0	£102.4
Survey costs	£2.5	£0.0	£3.7	£4.9	£2.5
Platform capex	£150.0	£40.0	£190.0	£265.0	£150.0
Drilling station capex	£232.7	£523.2	£889.7	£841.8	£329.1

Table 7.5 Breakdown of costs for EOR network.

The capital expenditures for the EOR system are shown in the table above. The main contrast to the centrally planned scenario is the higher proportion of cost invested in offshore platforms and pipelines. As a result, the overall component of capital expenditure related to capture is down from 78% (central scenario) to 49%. Fraction of capital costs related to sinks (platforms, drilling and surveying) is 25%, and the fraction to pipelines is 24%.

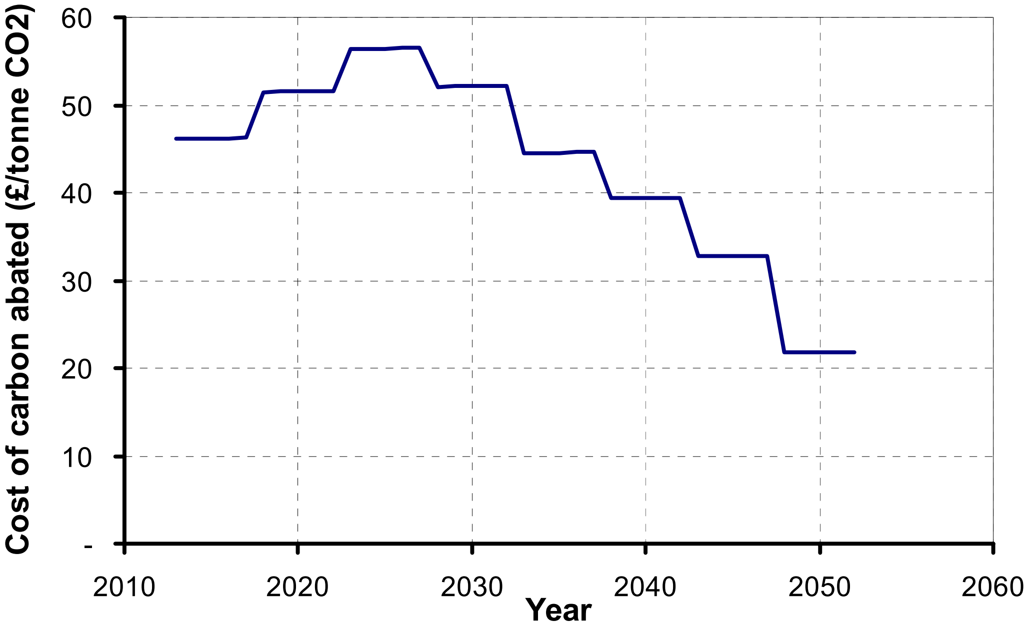


Figure 7-6: Cost of carbon abated per year, over the period of network development. To highlight savings due to increases in the efficient use of infrastructure over time, future costs are not depreciated. The costs do not include the revenues from EOR.

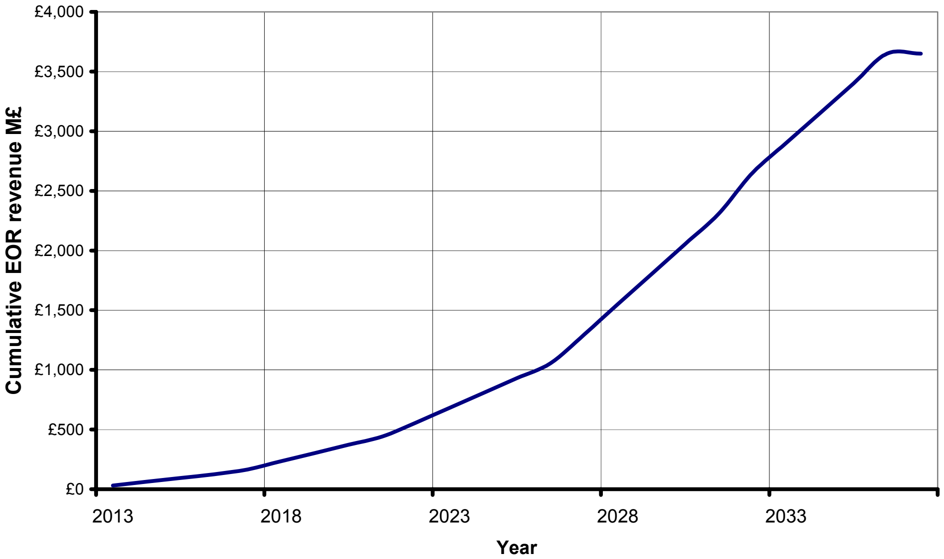


Figure 7-7: Cumulative oil revenues arising from CO_2-EOR (not depreciated)**.**

The figure above shows the cumulative additional oil revenues that are predicted to be generated by EOR. Over the system lifetime, an additional £3.5 billion of oil could be extracted (with a baseline oil valuation of £24/barrel).

7.3.1. Cost neutral conditions for EOR driven networks

With oil valued at £24/bbl, the additional costs of EOR outweigh the extra revenues from the sale of oil. The model was used to identify what the price of oil would need to be in order for the *net* cost of carbon (inclusive of EOR revenues) to be equivalent to that for non-EOR systems. It was found that at an oil price of £50/barrel:

- Cumulative oil revenues by 2037 are £8 billion (undepreciated) / £4.5 billion (depreciated).
- Net present system cost accounting for oil revenues, is £10 billion (excluding commercial financing) / £21billion (including commercial financing).
- Lifetime cost of carbon is £12/tonne (excluding financing) / £24/tonne (including financing).

It can be seen that at an oil price of £50/bbl (*ca.* $100/bbl), these cost of carbon figures are equivalent to the non-EOR scenario. Note that the same commercial loan rates are used for the EOR system (i.e. no additional risk is priced in).

8. CONCLUSIONS ON CCS NETWORK DEVELOPMENT

The issues facing CCS projects in general have been described in several reports covering technical, legal/regulatory[xxiv], environmental, economic[xxv,xxvi,xxvii], infrastructure[xxviii], health and safety[xxix], public acceptance[xxx], and cross-cutting issues[xxxi][xxxii]. The specific regulatory issues specifically facing the UK and Norway are also highlighted in a recent report from the North Sea Basin Task Force[xxxiii]. To avoid repetition, this section highlights issues that are additional to the above reports, and which arise directly from the current study.

8.1. Financial implications

This section highlights the commercial risks, implications and opportunities for intervention that relate specifically to the network development scenarios modelled in the previous chapter.

Centrally planned network.

- The significant volumes of CO_2 captured and transported in this scenario are likely only under a financial environment preferential for CCS, or through mandating the use of CCS for new generation. Both of these would require government to take an active position, directly (through a mandate) or indirectly (using the ETS to increase the market cost of carbon).
- Clustering (convergence of CO_2 supply) is an important aspect of the centrally planned network. While clustering does not reduce capture costs, oversizing of the transport infrastructure - to accommodate future capacity increases - works to reduce lifetime cost of carbon abated. Clustering also makes more efficient use of offshore platforms which are an important cost component in the model.
- Shorter term commercial pressures may prevent the oversizing of transport infrastructure, Additional infrastructure would then be required to handle the increased volumes of CO_2, which leads to higher lifetime system cost of capture.
- Even if interest rates were very low, the risk of CO_2 capacity increases not occurring on time (or at all) is a barrier to private firms oversizing CO_2 transport infrastructure. Some regulatory oversight or government investment would be required to ensure that effective transport system oversizing (as measured by lifetime cost of carbon abated) occurs.
- The capital cost of new offshore platforms is an important cost component. The first CO_2 source to connect to a new sink incurs a significant capital cost. As networks develop, the offshore infrastructure is used much more effectively resulting in a lower lifetime cost of carbon abated. The problem is analogous to electrical transmission systems, where new infrastructure (which ultimately benefits many) may have prohibitively high capital cost. Government oversight (potentially through a regulatory body) may be required.
- Assuming that a mixture of sinks (oil field, gas field and aquifers) are used, there is no sink resource limitation at any phase. UK sources will preferentially connect to UK sinks (pipeline lengths are lower and costs are less).
- The same applies to Norway, although the higher cost of deeper Norwegian sinks may encourage some joint exploitation of UK sinks. If CO_2 does cross national boundaries, international agreement allowing CO_2 transport, and associated liability transfer, between the UK and Norway would be required.

EOR-led network

- An EOR-led network is dependent on both a high oil price to encourage demand for CO_2, and a high carbon price in the ETS to encourage CO_2 supply.
- An EOR led CCS network is also dependent on CO_2-EOR being lower risk and lower cost than other EOR technologies; and that North sea CO_2-EOR is seen as attractive when measured against other opportunities for oil production unlocked by a high oil price.
- The additional oil revenues in the EOR scenario, are sufficient to offset the extra costs of the EOR system when oil is valued above £50/bbl (*ca.* $100/bbl).
- The cost component of offshore platforms in the EOR scenario is much higher than in the centrally planned. EOR platforms are more complex, resulting in higher capital and operating costs.
- A predictable tax regime, with reduced taxes and/or increased capital allowances for incremental oil produced by CO_2, should be considered as incentives for the generation of an EOR demand for CO_2[xxxiv].
- An EOR only network would likely have lower overall CO_2 abatement than for the centrally planned scenario. CCS would play less of a role in meeting national CO_2 reduction targets.
- Norway has more very large EOR fields than the UK. The conditions that favour EOR would support a (mainly Norwegian) demand for CO_2.
- This CO_2 could be supplied by other European countries with access to Norway or the North Sea, i.e. not just the UK. Although the NPD has recently concluded that EOR is not a priority as far as the Norwegian oil industry is considered, this may be because CO_2 from Norwegian sources is relatively expensive (e.g. from gas-fired rather than coal-fired sources).
- The proximity of southern North Sea countries (Germany and Denmark) to large, southerly Norwegian EOR fields suggests they could provide a source of CO_2 that is competitive with UK.

8.2. Non-financial implications

Central planned network

- As it is driven by a high carbon price, a range of sources develop, including coastal and inland. Recent experience with gas and electricity infrastructures suggests that government intervention may be required to reduce the risk associated with planning permission for onshore CCS infrastructures of a significant scale. In the context of the recent UK 2007 Planning White Paper, this could be in the form of a national statement of need for CO_2 pipelines.

- Assuming that the benefits of clustering can be unlocked through oversizing of transport infrastructures, clustering of sources is shown to have a beneficial effect in the medium-long term on the cost of carbon abated. Government will need to be mindful that the sitting of capture plant in the near term should take into account the potential longer term benefits of clustering. The effect is not as pronounced in Norway due to the distance and geography between sources.

- As a base case this model assumes new offshore platforms and wells will be required, which may prove pessimistic should reuse of existing infrastructure be possible. However the potential for reuse is specific to individual platforms and the information required to categorise them may be commercially sensitive. Particularly in early phases (where sinks costs are high) an approach where a limited number of sinks are examined in detail for their re-use potential, would prove beneficial. Governments may need to appoint a regulator to ensure issues of competitiveness, confidentiality, and efficiency related to third party access are balanced.

- For the centrally planned network a main driver is connecting to low cost sinks. This could best be exploited by joint UK-Norwegian use of a limited number of sinks. This spreads the platform cost through a greater volume of CO_2 and would reduce the relatively high cost of early networks.

EOR led network

- Given the increased trading of CO_2 between the UK and Norway in this scenario, the market may wait to see how CCS is included within international treaties (successors to Kyoto, and within the ETS) and clear liabilities are defined for leakage from pipeline and sinks. The UK and Norway should continue to support these discussions.

- Re-use of existing infrastructure or sharing of infrastructure requires exchange of commercially sensitive data between different industries, and potentially between competitors within the same industries. Governments may need to appoint a regulator to ensure issues of competitiveness, confidentiality, and efficiency related to third party access are balanced

- The issue of offshore platform assessment for re-use (see above) is more pertinent for EOR networks, and the requirement for openness while maintaining competitiveness again suggests that a regulator or independent party may be required.

- The sinks owned by the UK and Norway are relatively well characterised. Under market conditions favouring CCS, these sinks would prove attractive to other North Sea countries such as Germany and Denmark.

8.3. Issues common to both development scenarios

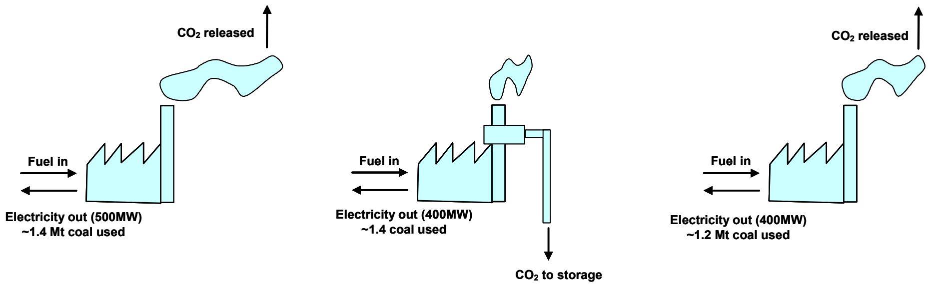
- The dynamic environment within which CCS networks would develop introduces significant uncertainty and may require an oversight, regulatory or mandatory role by government to encourage CCS development.
- Oversizing of infrastructure to achieve lowest lifetime cost of carbon requires considerable assumptions about future supply and demand for CO_2. Government may need to insulate private operators from potential downsides of oversizing (due to reduced or delayed connection of CO_2).
- While EOR may be required to encourage demand for CO_2, strong mechanisms will be required to support the supply/generation of CO_2. A compulsion based mechanisms such as mandating CCS for new build (and retrofit) with clear deadlines, could operate similarly to the Large Combustion Plant Directive. This strong mechanism would also significantly reduce risk with regard to uncertainty when planning a CCS network.
- For electricity generators, power plants fitted with CO_2 capture facilities and connected to a transport and storage network will be more expensive in terms of up-front and on-going costs, and in the absence of a high CO_2 price or other economic support, this gives them low positions in the merit curve. Regulation may be required to make sure plants fitted with capture equipment run at base-load, and not peak-load conditions. This will result in higher amounts of CO_2 being abated and at lower overall costs.
- For optimal sink screening, an economic model (e.g. licensing) should be developed so that potential sink operators can deploy resources and manage risk effectively.
- Amendments to North Sea pipeline/platform and well decommissioning legislation and best practice should be examined to quantify potential network cost reductions these may bring if equipment is re-used for CCS.
- A framework should be developed defining how shorter-term and longer-term liabilities for CO_2 are assigned when multiple sources, pipelines and sinks are connected.

9. APPENDIX

9.1. Capture vs. Abatement

A key issue in the economics of carbon capture and storage is the difference between carbon captured and carbon abated. As mentioned above, capturing and compressing CO_2 requires energy, which means that it will dispatch the same amount of power as a smaller size unit running at the same load factor.

The diagram below illustrates how a 500 MW unit will continue to use the same volume of fuel but send out 400 MW of power once capture facilities are fitted. The model specifies a hypothetical unit, that is identical to the original units except that its capacity has been adjusted to it will despatch the same amount of electricity when running at the same load factor. The unit is referred to as the counterfactual.



Existing unit without CCS releases ~3.0 Mt CO_2

Existing unit with CCS releases ~ 0.4 Mt CO_2

Uses same fuel as existing unit but less electricity sent out

Same fuel counterfactual releases ~2.5 Mt CO_2

Generates same electricity as unit with CCS sends out but uses less fuel

Figure 9-1 Capture vs. abatement

The subsequent analysis uses the following equations:

$$Electrical\ output\ (TWh) = 8{,}760 \times Capacity \times Load\ Factor$$

In the UK there is a mix of coal and gas plants, and the load factor will change depending on whether fuel prices favour gas or coal. When they favour gas, the load factor is assumed to be 48% for pulverised coal units and 80% for CCGTs. When fuel prices favour coal, the load factor is assumed to be 87% for pulverised coal units and 55% for CCGTs. All of the Norwegian units considered are gas-fired, so the load factor is 90% regardless of fuel prices. All of the industrial sites are assumed to operate at a load factor of 90%.

The capacity times the load factor is multiplied by the number of hours in a year, 8,760, to estimate the amount of electricity generated in a year.

$$Fuel\ used\ (TWh) = \frac{Electrical\ output\ (TWh)}{Efficiency}$$

$$Carbon\ emissions\ (MtCO_2) = Fuel\ used\ (TWh) \times Emission\ Factor\ (tCO_2 / MWh)$$

The Emission Factors used are:

- 0.3 tCO_2/MWh for coal; and;
- 0.19 tCO_2/MWh for gas.

The model estimates the volume of electricity sent out, the fuel used and the emissions of CO_2 for the original unit, the original unit with capture facilities and the counterfactual. This makes it possible to determine the:

- additional fuel needed to operate the carbon capture facilities, i.e. the difference between the amount of fuel actually used and that which the counterfactual would have used;
- volume of CO_2 captured, i.e. the difference between the emissions from the original unit and the unit with capture facilities, in the above example 3.0 – 0.4 = 2.6 $MtCO_2$; and
- volume of CO_2 abated, i.e. the difference between the emissions from the counterfactual and the unit with capture facilities, in the above example 2.5 – 0.4 = 2.1 $MtCO_2$.

It is necessary to dimension the capture, transport and storage facilities to be able to process the volume of CO_2 captured. When estimating the unit cost of CO_2 abated, i.e. £/tCO_2, the costs of the facilities are divided by the volume of CO_2 abated. The effect is to include the cost of capturing, transporting and storing the CO_2 released when producing the energy to run the capture facilities into the cost of abatement.

9.2. Sinks assumptions

9.2.1. Calculation of storage capacity of UK gasfields.

The methodology used to estimate the storage capacity of the UK's gas fields is based on the principle that a variable proportion of the pore space occupied by the recoverable reserves will be available for CO_2 storage, depending mainly on the reservoir drive mechanism (e.g. Bachu & Shaw 2003)[xxxvi]. The mass of CO_2 that would occupy the pore space in each field formerly occupied by its recoverable reserves of natural gas is calculated according to the following formula:

$$M_{CO2} = (V_{GAS}\,(stp) / Bg) \,.\, \rho CO_2 \qquad \text{(Equation 1)}$$

Where:
M_{CO2} = CO_2 storage capacity (10^6 tonnes)
Stp = standard temperature and pressure
V_{GAS} (stp) = volume of ultimately recoverable gas at stp (10^9 m^3)
Bg = gas expansion factor (from reservoir conditions to stp)
ρCO_2 = density of CO_2 at reservoir conditions (kg m^{-3})

The density of CO_2 at reservoir conditions was calculated from an equation of state (Span and Wagner 1996)[xxxv].

The above figure is then discounted to allow for factors that may reduce the amount of pore space in the reservoir that could be filled with CO_2. Water invasion into the reservoir during (and after) gas production is considered to be the main factor that will affect the amount of CO_2 that can be injected back into the gas field. This can most accurately be estimated by using a detailed numerical reservoir simulation. Unfortunately no reservoir simulations were available for this study. In the absence of simulations, the following factors, similar to those used by Bachu & Shaw (2003)[xxxvi] in their study of the CO_2 storage capacity of the oil and gas fields of Alberta, were used to discount the CO_2 storage capacity calculated in Equation 1:

1. In gas fields where depletion drive dominates, i.e. those where the wells are opened up and the pressure in the gas field simply depletes as it would if the gas were being produced from a sealed tank, it is assumed that 90% of the pore space could be occupied by CO_2.
2. In gas fields where water drive dominates, i.e. those where water encroaches into the pore space formerly occupied by the produced natural gas reserves, it is assumed that 65% of the pore space could be occupied by CO_2.
3. Where the drive mechanism is unknown, it is conservatively assumed that 65% of the pore space could be occupied by CO_2.

For the UK sector, Gas Initially In Place (GIIP), Ultimately Recoverable Reserves (URR), Gas Expansion Factor (GEF), Initial Reservoir Pressure, Initial Reservoir Temperature were taken from DTI (2001)[xxxvii], Abbotts (1991)[xxxviii] and Gluyas & Hichens (2003)[xxxix] and drive mechanisms were taken from Abbotts (1991)[xxxviii] and Gluyas & Hichens (2003)[xxxix]. For the Norwegian sector, the estimates of Boe (2002)[xvi] were discounted appropriately.

9.2.2. Start dates and availability of EOR sinks

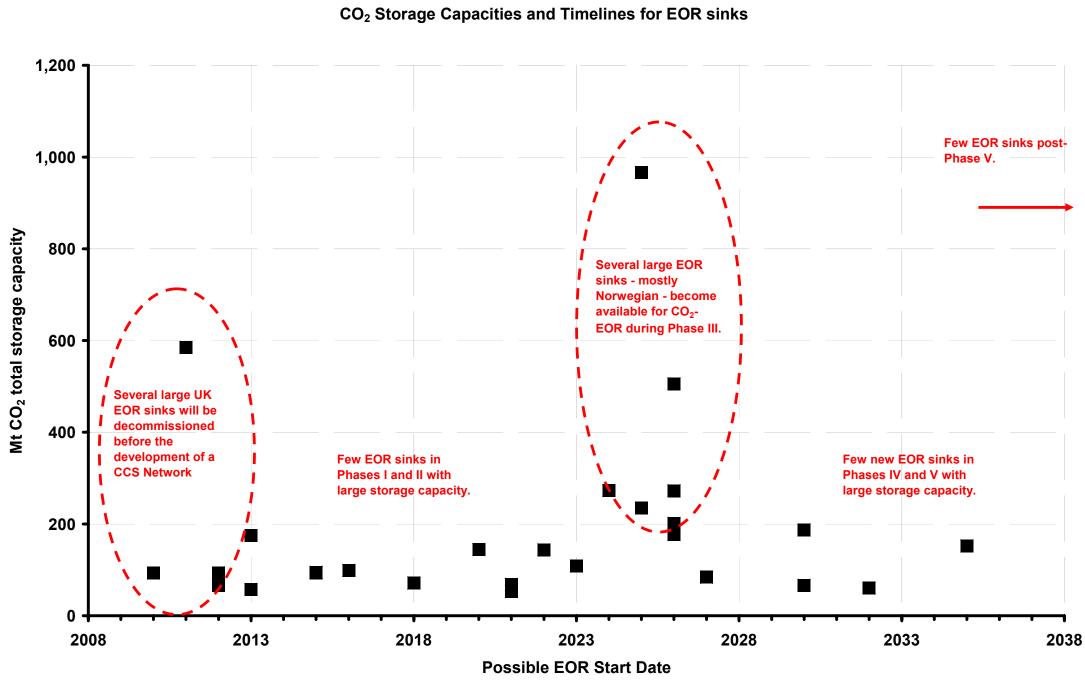


Figure 9-2 Timeline indicating the strong time dependence of the availability of EOR sinks. Data taken from DTI/NPD/ECL. Timing is strongly dependent on market forces (e.g. oil price and technology developments). Phase I starts in 2013. Phase V ends in 2037. Wells with storage capacities less than 50 Mt are omitted from the graph for clarity but have been included in the study. <Field names omitted in public report>.

9.2.3. Sink Selection for Networks

An iterative process was used to prepare shortlists of sinks for consideration in a network model. This is described below:

To identify the most relevant sinks for CCS, the sinks in the database were sorted according to overall storage capacity, availability in any one of the five phases (based on published close of production dates), and in the case of EOR, expected oil yield from EOR and EOR start date.

67 sinks in the database have a capacity of at least 100 Mt CO_2. Historically power plants have tended to run for 25-50 years, and offshore platform lifetimes are 10-30 years. Taken together 100 Mt CO_2 seems a reasonable *minimum* useful lifetime capacity required for a large number of single projects - satisfying demands of 2.5 Mt/year for 40 years or 5 Mt/year for 20 years. Therefore, sinks with a capacity of less than 100 Mt are excluded (except where they have significant EOR potential, see below). This considerably reduces the storage capacity available.

4 out of 32 UK aquifers are classed as lowest risk on the basis of fault data. Of these, three have a capacity over 100 Mt. The remaining 29 UK aquifers are not used for the purpose of network modelling. This strikingly reduces the storage capacity available.

In the case of EOR, sinks were sorted on the basis of availability during the relevant phase based on EOR start date listed in the database. UK and Norwegian sinks were then ranked according to remaining oil reserves. Sinks were then chosen on the basis of largest EOR opportunity coupled to largest storage opportunity, and proximity. In the case of Norwegian sinks, high priority was given to Norwegian sinks identified as part of useful value chains in recent publications (e.g. the Gassco report[xv], and NVE's report on CCS at Karsto[xl]).

Gas fields or oil fields were deemed available for storage only in a given phase only if their COP fell during that phase or immediately (within a year) beforehand. Gas fields were deemed unavailable five years after their close of production.

9.2.4. Infrastructure Re-Use Scenarios

As illustrated in the following figures, infrastructure re-use is most likely for storage of CO_2 in depleted gasfields and oilfields (without EOR).

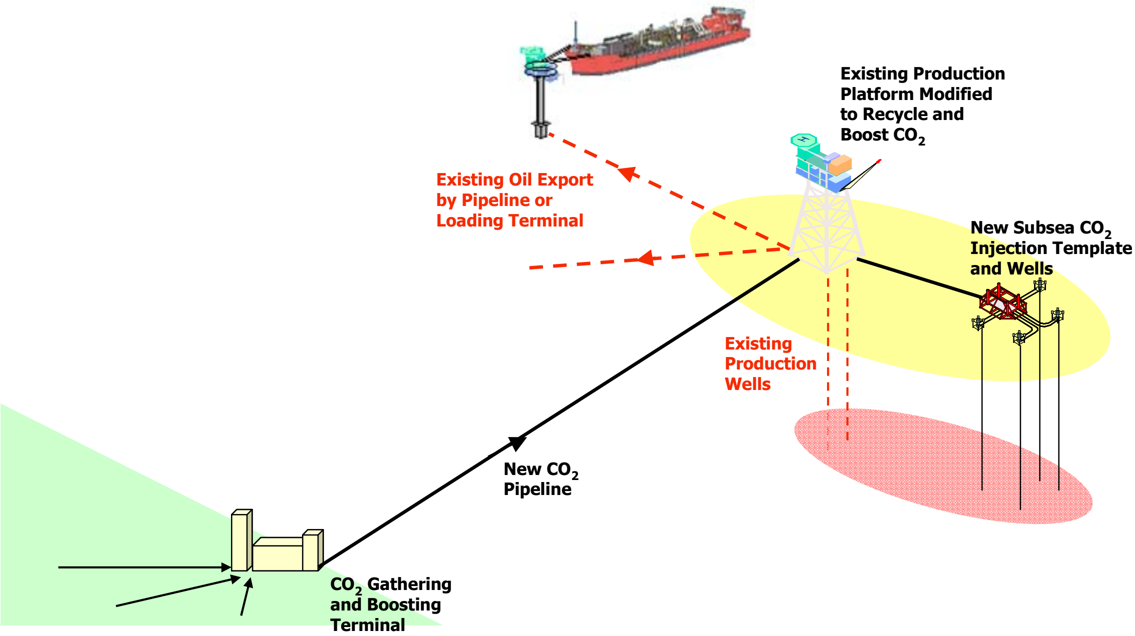


Figure 9-3 CO_2 injection in an existing oilfield for EOR

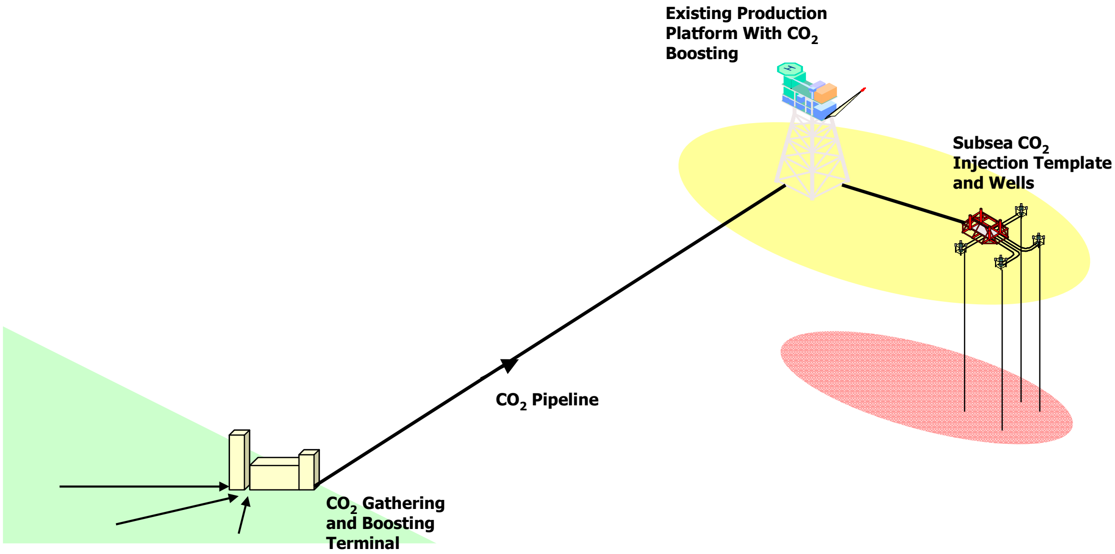


Figure 9-4 CO_2 injection in oilfield for storage post-EOR

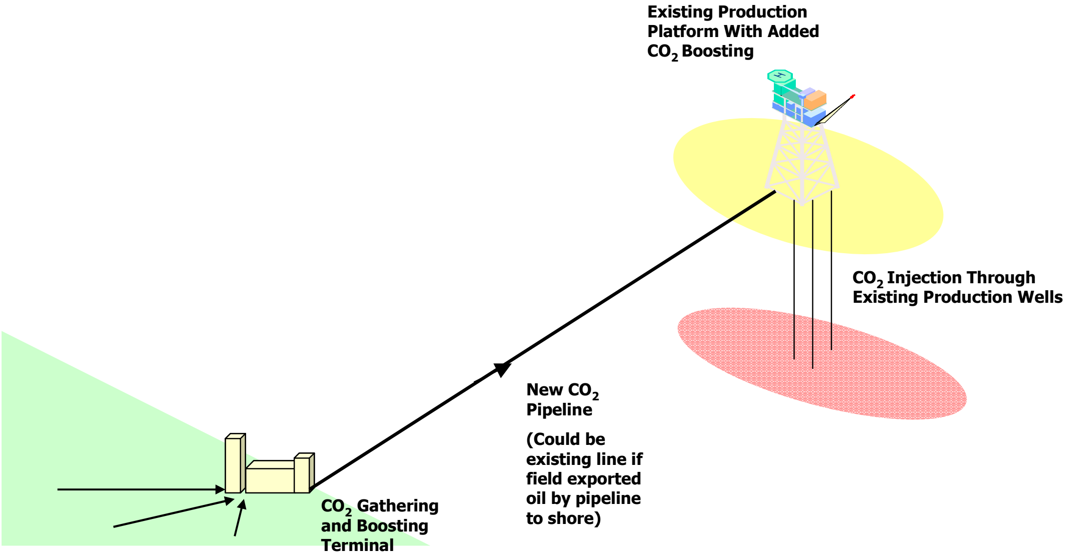


Figure 9-5 CO_2 injection for storage in oilfields without EOR

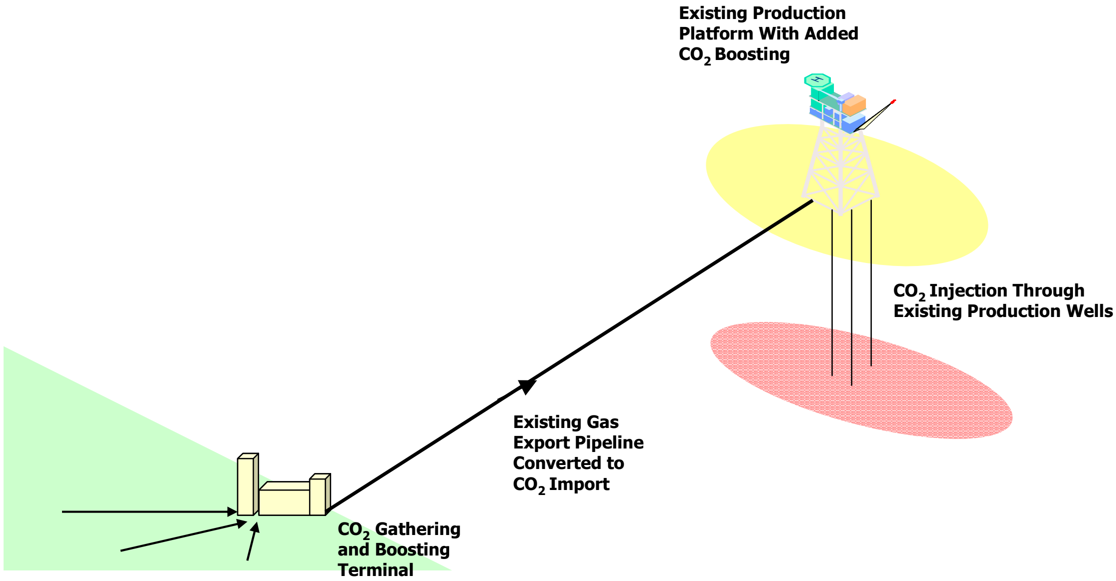


Figure 9-6 CO_2 injection in depleted gas field. Note that pipeline availability depends on whether the existing pipeline also services nearby fields.

Scenario 5 - CO_2 Injection in Aquifer

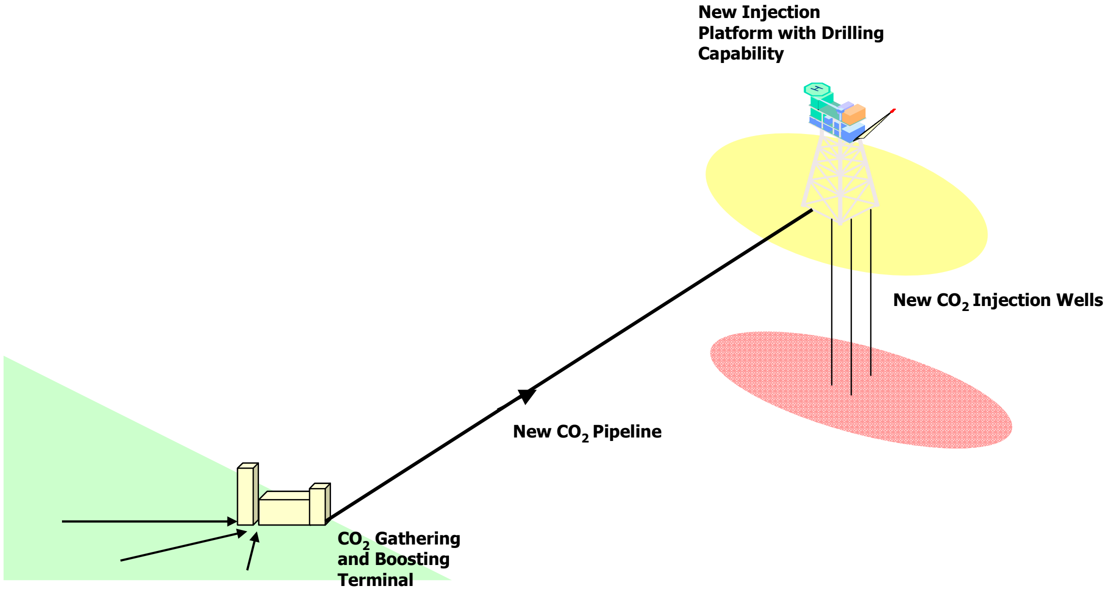


Figure 9-7 CO_2 injection in aquifer. Entirely new infrastructure expected for pipelines, platforms and wells.

9.3. Sink cost assumptions

Sink costs assumptions are identified below

OIL FIELDS (STORAGE AND EOR)		
Lifespan	20	years
Injection capacity per well	1.25	10^6 tonnes/yr
Horizontal drilling distance	1,000	m
Ratio of horizontal drilling cost over vertical	2	
Drilling shallow to deep changeover	3,000	m
Survey & development costs	1,226,542	£ (yr 2005)
Platform shallow to deep changeover	100	m
Oil price	23.89	£/bbl (yr 2005)
Oil production costs	4.50	\$/bbl (yr 2005)
Oil production costs	2.62	£/bbl (yr 2005)
Maximum number of wells per platform	20	

GAS FIELDS (GAS AND CONDENSATE)		
Lifespan	20	years
Injection capacity per well	1.25	10^6 tonnes/yr
Horizontal drilling distance	1,000	m
Drilling shallow to deep changeover	3,000	m
Survey& development costs	1,226,542	£ (yr 2005)
Platform shallow to deep changeover	100	m
Displacement Drive factor	0.90	
Water Drive factor	0.65	
Unknown drive mechanism factor	0.65	
Maximum number of wells per platform	20	

AQUIFERS		
Lifespan	20	years
Injection capacity per well	1.25	10^6 tonnes/yr
Horizontal drilling distance	1,000	m
Drilling shallow to deep changeover	3,000	m
Survey& development costs	1,226,542	£ (yr 2005)
Platform shallow to deep changeover	100	m
Maximum number of wells per platform	20	

Drilling costs

For all sinks, the model has a fixed and variable component to drilling costs.

- Fixed cost per well (shallow water): £5.6m
- Fixed cost per well (deep water): £8.3m
- Drilling cost (shallow water shallow reservoir): 2,600 £/m
- Drilling cost (shallow water deep reservoir) 3640 £/m
- Drilling cost (deep water shallow reservoir) 4400 £/m
- Drilling cost (deep water deep reservoir) 6660 £/m

The drilling cost model also takes account of the horizontal component of drilling.

Platform costs

The platform cost model differentiates between EOR and non-EOR platforms.

Non-EOR platforms:

Shallow water	*Deep water*
Cap. ex. £40m	Cap. ex. £75m
Op. ex. 2% of cap. ex.	Op. ex. 2% of cap. ex.

EOR platforms:

Shallow water	*Deep water*
Cap. ex. £140m	Cap. ex. £280m
Op. ex. 10% of cap. ex.	Op. ex. 10% of cap. ex.

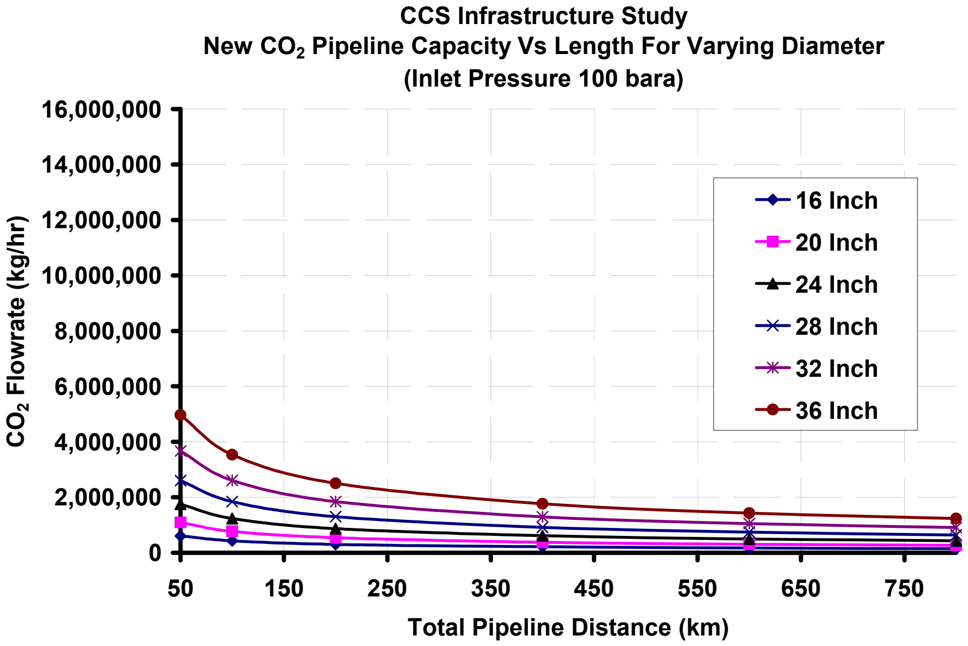
The costs of monitoring are not included in this study, and are small by comparison with overall costs.. Schlumberger have estimated costs as :

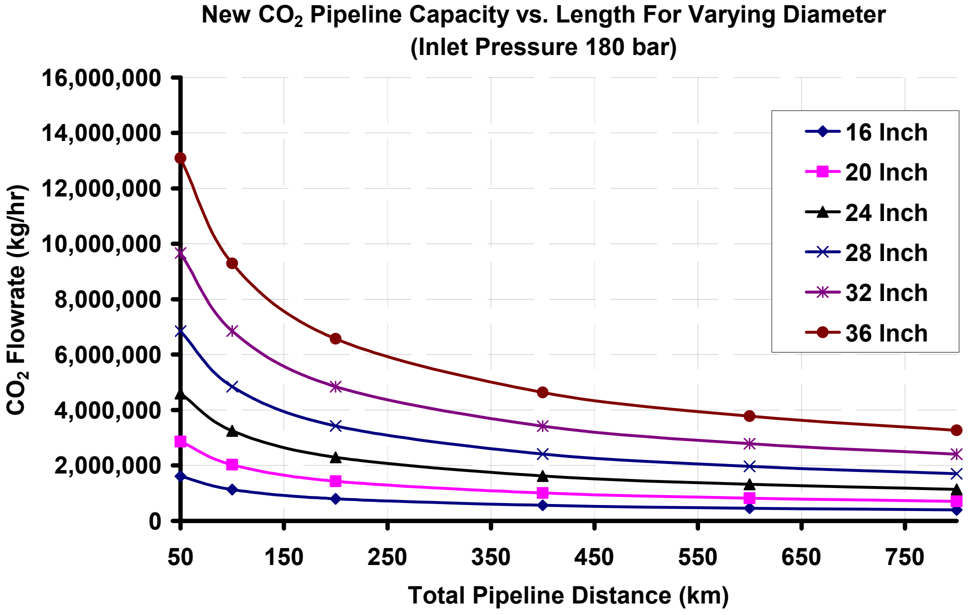
- Seismic time-lapse - $10-15M (for 200 km^2 survey,1 month acquisition, 2 month processing).

Permanently installed monitoring temperature or pressure in a well - ~0.3-0.5 $/t CO$_2$ stored.

9.4. Pipeline issues

The following graphs illustrate the relationship between pipeline internal (note: not external) diameter, length, inlet pressure and CO_2 capacity for a fixed delivery pressure of 85 bar. They can be used for sizing of new lines and for determining the capacity of existing oil and gas lines.





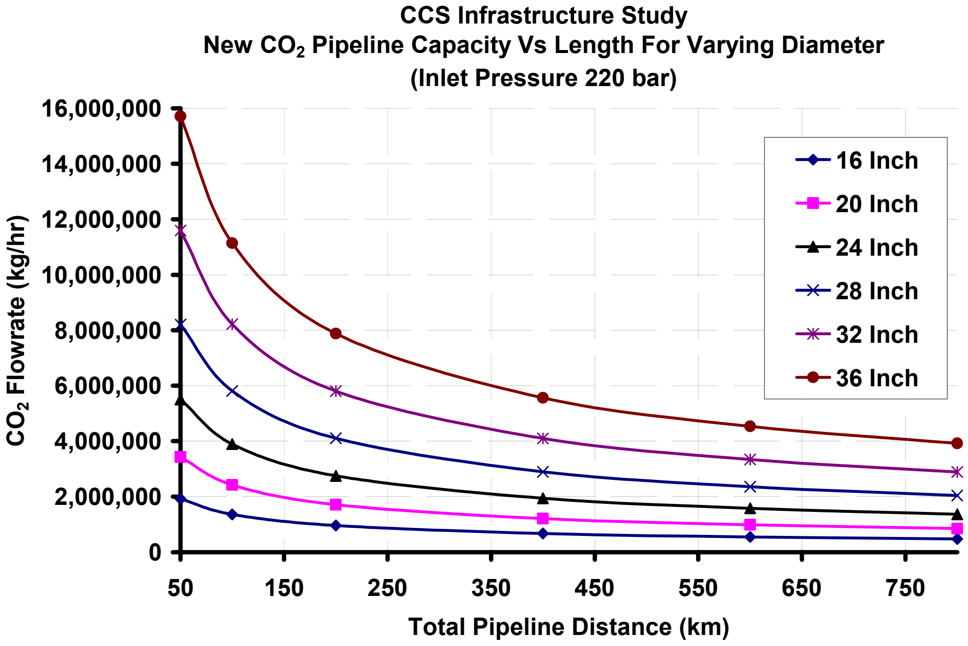


Figure 11.4 Graphs of CO_2 flow-rate as a function of pipe distance and internal diameter. For reference, 10,000,000 kg CO_2/hour is equivalent to 87.6 Mt CO_2/year.

Landfall	Pipeline Name	Hub Field/Facility	Length	Diameter	Design Pressure	Current Service	Capacity (Oil/Gas)	Capacity (CO2)	Year Installed	Age	Operator
Bacton	Bacton-Leman I	Leman 49/27A	61 km	30	100 bar	Gas	900 mmscfd	15 mtpy	1971	36	
	Inde - Leman	Inde 49/23A	36 km	30	110 bar	Gas		15 mtpy	1971	36	
	Bacton - Leman II	Leman 49/27B	65 km	30	110 bar	Gas	900 mmscfd	15 mtpy	1971	36	
	Bacton - Leman III	Leman 49/26B	58 km	30	100 bar	Gas	1000 mmscfd	15 mtpy	1973	34	
	Bacton - Leman IV	Leman 49/26A	56 km	30	100 bar	Gas	1000 mmscfd	15 mtpy	1967	40	
	Bacton - Hewett I	Hewett 48/29 FTP	32 km	30		Gas		15 mtpy	1968	39	
	Bacton - Hewett II	Hewett 48/29 FTP	29 km	30		Gas		15 mtpy	1973	34	
	Bacton - Esmond	Esmond	204 km	24	140 bar	Gas	334 mmscfd	15 mtpy	1984	23	BHP
	Bacton - Thames	Thames	89 km	24	110 bar	Gas		10 mtpy	1986	21	
	Bacton - Lancelot	Lancelot	61 km	20		Gas	220 mmscfd		1993	14	
	SEAL	Elgin	463 km	34		Gas	26 m3/d		1998	9	Total/Shell
Theddlethorpe	LOGGS	LOGGS Gathering Station	120 km	36	130 barg	Gas	2000 mmscfd	45 mtpy	1987	20	
	Viking	Viking	136 km	28	130 barg	Gas	918 mmscfd	25 mtpy	1971	36	
	Pickerill	Pickerill	66 km	24		Gas			1991	16	
	CMS	Murdoch	174 km	26	153 barg	Gas	1m3/d (750 mmscfd	20 mtpy	1992	15	ConocoPhillips
Easington	West Sole I	West Sole WA	70 km	16	160 bar	Gas		10 mtpy	1966	41	
	West Sole II	West Sole WB	68 km	24	160 bar	Gas		20 mtpy	1981	26	
	Rough I	Rough AP	29 km	16		Gas			1975	32	Centrica
	Rough II	Rough BP	29 km	36	100 bar (OP)	Gas	1000 mmscfd	25 mtpy	1982	25	Centrica
	Ravenspurn	Ravenspurn				Gas					
Teesside	Norpipe	Ekofisk 2/4P	220 mi	34	125 bar (OP)	Oil	1 mill bopd	20 mtpy	1975	32	ConocoPhillips
	CATS	Everest	397 km	36	2000 psig	Gas	40 m3/d	30 mtpy	1992	15	BP
St Fergus	Fulmar	Fulmar	290 km	20	181 bar	Gas	14 m3/d	10 mtpy	1984	23	Shell
	Britannia	Britannia	195 km	26	180 bar	Gas	1 m3/d (950 mmscfc	25 mtpy	1997	10	BOL
	Miller	Miller	242 km	30	175 bar (OP)	Gas	31 m3/d	30 mtpy	1990	17	BP
	SAGE	Beryl	325 km	30		Gas	33 m3/d		1990	17	ExxonMobil
	Frigg - St Fergus I	Frigg	360 km	32	143 bar	Gas	45 m3/d	25 mtpy	1975	32	Total/Gassco
	Frigg - St Fergus II	Frigg	360 km	32	143 bar	Gas	45 m3d	25 mtpy	1977	30	Total/Gassco
	FLAGS	Brent A	448 km	36	140 bar	Gas	31 m3/d	25 mtpy	1976	31	Shell
Cruden Bay	Forties I	Forties C	170 km	32"		Oil	630,000 bopd		1974	33	Apache
	Forties II	Forties C	170 km	36"		Oil	900,000 bopd		1990	17	Apache
Nigg	Beatrice	Beatrice A	67 km	16	148 bar (OP)	Oil	100,000 bopd	10 mtpy	1979	28	Talisman
Flotta	Piper - Flotta	Piper B / Claymore	169 km	30	160 bar	Oil	560,000 bopd	30 mtpy	1975	32	Talisman
Sullom Voe	Brent Oil	Cormorant A									
	Ninian Oil	Ninian Central	161 km	36	133 bar	Oil	945,000 bopd	45 mtpy	1976	31	CNR
Barrow	Morecambe Bay I	Morecambe CPP1	38 km	36	33 bar (105 bar OF	Gas	1800 mmscfd	50 mtpy	1982	25	BG
	Morecambe Bay II	North Morecambe	40 km	36		Gas			1993	14	BG
Point of Ayr	Douglas	Douglas	33 km	20		Gas			1994	13	BHP

Table 9.1 Trunklines in the UK sector of the North Sea that may be suitable for CO_2 transport. <Start dates omitted from public report>.

Landfall	Pipeline Name	Hub Field	Linked Fields	Length	Diameter	Design Pressure	Current Service	Capacity (Oil/Gas)	Year Installed	Age	Operator
Karsto	Statpipe I	Draupner Riser Platform	Heimdal (155km/36"/156bar) Ekofisk (203km/36"/156bar)	228 km	28	172 bar	Gas	20 mill scm/d	1984	23	Statoil
	Statpipe II	Statfjord	Brage Veslefrikk Gullfaks Snorre	308 km	30	172 bar	Gas	25 mill scm/d	1984	23	Statoil
	Asgard Transport	Asgard	Draugen (78km/16") Heidrun Norne (126km/16") Kristin	707 km	42	N/A	Gas	69 mill scm/d	2000	7	
	Sleipner Condensate	Sleipner	Loke Sigyn Gungne	230 km	20	N/A	Condensate	200,000 bbl/d	1992	15	Statoil
Kollsnes	Zeepipe IIA	Sleipner Riser Platform		294 km	40	N/A	Gas	72 mill scm/d	1995	12	Gassco AS
	Zeepipe IIB	Draupner Riser Platform		292 km	40	N/A	Gas	71 mill scm/d	1996	11	Gassco AS
	Troll	Troll	Oseberg	2 x 65 km	36	N/A	Gas	100 mill scm/d	1995	12	
	Kvitebjorn	Kvitebjorn	Visund								
Sture	Grane Oil	Grane	Heimdal	220 km	29	N/A	Oil	34,000 scm/d	2003	4	Norsk Hydro
	Oseberg Transport System (OTS)	Oseberg	Veslefrikk Brage Oseberg S and E Tune Huldra	115 km	28	154 bar	Oil	600,000 bopd	1987	20	
Mongstad	Troll Oil I	Troll B	None	85 km	16	185 bar	Oil	42,500 scm/d	1995	12	Statoil
	Troll Oil II	Troll C	Fram Kvitebjorn (90km/16")	80 km	20	N/A	Oil	47,500 scm/d	1999	8	Statoil
Nyhamna	Ormen Lange	Ormen Lange	None			N/A	Wellstream Gas				
	Langeled	Sleipner Riser Platform			42	N/A	Gas	80,000 scm/d	2007	0	Gassco AS
Tjeldbergodden	Haltenpipe	Heidrun Asgard		250 km	16	N/A	Gas	2.2 bn scm/yr			

Table 9.2 Trunklines in the Norwegian sector that might be suitable for CO_2 transport.

9.5. Network Issues

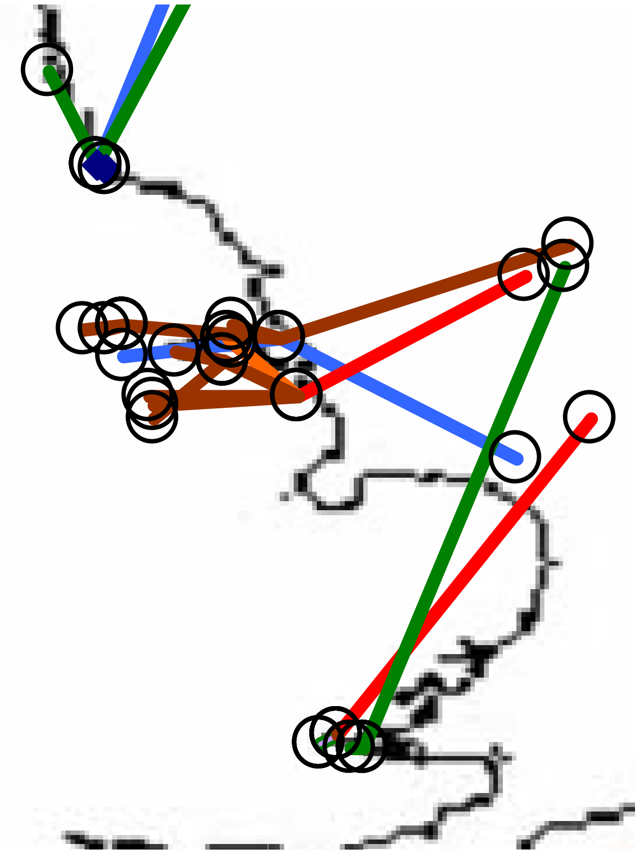


Figure 9-8 Enlargement of network map highlighting the use of a limited number of hubs for a Centrally Planned Scenario. Pipelines are colour-coded according to year they are laid. Blue

pipelines are built in Phase I, Red pipelines in Phase II, Green Pipelines built in Phase III, Orange pipelines in Phase IV and Brown pipelines in Phase V.

<TABLE 9.3 OMITTED FROM PUBLIC REPORT>

Table 9.3 List of sources, sinks and terminals used for the Centrally Planned Scenario. Network growth rates are illustrative.

<TABLE 9.4 OMITTED FROM PUBLIC REPORT>

Table 9.4 List of sources, sinks and terminals used for EOR-led scenario. Network growth rates are illustrative.

---

[i] International Panel on Climate Change (2005) Special report on Carbon Capture and Storage

[ii] HM Government (2006) “The Energy Challenge”

[iii] HM Treasury (2006) “Stern Review: The Economics of Climate Change”

[iv] DTI (2007) The Energy White Paper

[v] DEFRA - UK National Allocation Plan for EU ETS Phase II.

[vi] Platts Power in Europe - new power plant project tracker

[vii] Pöyry database of power generation

[viii] Paterson, G. 2003. Enhanced Gas Recovery Potential from CO_2 Injection into Depleted Dry Gas Reservoirs. Sharp IOR eNewsletter, October 2003, Issue 6. http://ior.rml.co.uk/issue6/rnd/SMEs/ECL_CO2/ecl_co2.htm

[ix] Holloway, S., Vincent, C.J. & Kirk, K.L. 2006a. *Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK.* DTI Cleaner Fossil Fuels Programme Report No. COAL R308, DTI/Pub URN 06/2027.

[x] ECL, 2002 (updated 2004). UKCS CO_2 EOR /Sequestration potential. Report LCU-IOR-1/506/1346/v2. Commercial-in-Confidence.

[xi] Mathiassen, O.M. 2003. CO_2 as Injection Gas for Enhanced Oil Recovery and Estimation of the Potential on the Norwegian Continental Shelf. MSc Thesis, Norwegian University of Science and Technology, Trondheim.

[xii] Tzimas, E., Georgakaki, A., Garcia Cortes, C. & Peteves, S.D. 2005. *Enhanced Oil Recovery using Carbon Dioxide in the European Energy System*. European Commission Directorate General Joint Research Centre Report EUR 21895 EN, Institute for Energy, Petten, Netherlands. http://www.jrc.nl/

[xiii] Holloway, S. & Baily, H.E. 1996 . The CO_2 Storage Capacity of the United Kingdom. In: *In:* Holloway, S. (ed.), *The Underground Disposal of Carbon Dioxide*. Final Report of Joule 2 Project No. CT92-0031. British Geological Survey, Keyworth, Nottingham, pp. 92-105

[xiv] Boe, R., Magnus, C., Osmundsen, P.T. & Rindstad, B.I. 2002. *CO_2 point sources and subsurface storage capacities for CO_2 in aquifers in Norway.* NGU Report No. 2002.010, ISSN 0800-3416, 132 pp. Geological Survey of Norway, Trondheim.

[xv] Gassco, 2006. Preliminary negotiations between players in a CO_2 chain. Document No. OKU-RA-6004. (Made available in English by NPD).

[xvi] Boe, R., Magnus, C., Osmundsen, P.T. & Rindstad, B.I. 2002. *CO_2 point sources and subsurface storage capacities for CO_2 in aquifers in Norway.* NGU Report No. 2002.010, ISSN 0800-3416, 132 pp. Geological Survey of Norway, Trondheim.

[xvii] Holloway, S., Vincent, C.J., Bentham, M.S. & Kirk, K.L. 2006b. Top-down and bottom-up estimates of CO_2 storage capacity in the UK sector of the Southern North Sea Basin, *Environmental Geoscience,* **13**(2): 74-81.

[xviii] Kirk, K.L. 2006. Storing carbon dioxide in the rocks beneath the East Irish Sea. *Proceedings of the GHGT-8 Conference, Trondheim, Norway, 19-22 June 2006*.

[xix] Dr. A. K. Booer, Schlumberger (personal communication)

[xx] Dr. A. K. Booer, Schlumberger (personal communication)

[xxi] Dr. A. K. Booer, Schlumberger (personal communication)

[xxii] Genesis Oil and Gas Consultants Ltd (2002) Offshore CO_2 Injection – Facilities Impact Evaluation, prepared for Department of Trade and Industry.

[xxiii] East of England Energy Group (2006) The Re-Use of Offshore Oil and Gas Pipelines Report and recommendations relating to the UKCS Pipeline System

[xxiv] Mace, M. J., Hendriks, C., and Coenraads, R (2007) Regulatory challenges to the implementation of carbon capture and geological storage within the European Union under EU and international law. *International journal of greenhouse gas control 1* (2007) 253 – 260.

[xxv] Sintef Petroleum Research, CO2-Norway AS, Norwegian School of Management, Center for International Climate and Environmental Research – Oslo, Faculty of Law and Institute for Petroleum and Maritime Law (2004) Large-Scale CO_2 Sequestration on the Norwegian Continental Shelf: A Technical, Economic, Legal and Institutional Assessment.

[xxvi] McCollum, D., L. and Ogden, J. M., (2006) Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity

[xxvii] IEA (2004) Prospects for CO_2 capture and storage

[xxviii] Kristoffersen, B and Palm, T (2006) ZERO-memo CO_2 infrastructure on the Norwegian British Shelf.

[xxix] HSE (2006) The Health and Safety Risks and Regulatory Strategy related to energy developments: An expert report by the HSE contributing to the Government's Energy Review 2006.

[xxx] Shackley, S., McLachlan, C., and Gough, C (2004) The public perceptions of carbon capture and storage. Tyndall Centre Working Paper 44.

[xxxi] Anderson, J., de Coninck, H., Curnow P., Flach, T., Groenenberg, H., Norton, C., Reiner, D., Shackley, S., and Sigurthorsson, G (2007) Identified gaps within thematic areas of CCS (Deliverable D.32 from ACCSEPT).

[xxxii] Gough, C., Shackley, S., Holloway, S., Bentham, M., Bulatov, I., McLachlan, C., Klemes, J., Purdy, R. and Cockerill, T. (2006) An Integrated Assessment of Carbon Dioxide Capture and Storage in the UK. Tyndall Technical Report 47. Final Report Project T2/21

[xxxiii] North Sea Basin Task Force (2007) Storing CO_2 under the North Sea Basin – a key solution for combating climate change.

[xxxiv] For examples see Coleman, D.L., Hustad, C.W., Austell, J.M. (2004) A logistic and economic perspective on delivering CO2 for EOR projects in the North Sea in Paper #332 – *Seventh International Conference on GHG Control Technologies*, Vancouver, Canada, 5 – 9 Sept 2004; Hustad, C-W., Austell, J.M. and Coleman, D.L. (2004). "Fiscal Mechanisms to Promote CO2 for EOR in the North Sea: Understanding the CO_2 Value Chain". in *Seventh International Conference on GHG Control Technologies*, Paper No.224, Vancouver, Canada, 5 – 9 Sept.

[xxxv] Span, R. and W. Wagner, 1996, A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 100 K at pressures up to 800 MPa", *J. Phys. Chem. Ref. Data,* **25** (6),1509 - 1596.

[xxxvi] Bachu, S. and J. Shaw, 2003, Evaluation of the CO_2 Sequestration Capacity in Alberta's Oil and Gas Reservoirs at Depletion and the Effect of Underlying Aquifers. *Journal of Canadian Petroleum Technology,* **42**(9), 51-61.

[xxxvii] DTI (UK Department of Trade and Industry), 2001, Development of UK Oil and Gas Resources 2000. The Stationery Office, Norwich, UK, 168 pp.http://www.dbd-data.co.uk/bb2001/book.htm

[xxxviii] Abbotts, I.L. (ed.), 1991, *United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume.* Geological Society, London, Memoirs, **14,** 573 pp.

[xxxix] Gluyas, J.G. and H.M. Hichens (eds), 2003, *United Kingdom Oil and Gas Fields, Commemorative Millenium Volume*, Geological Society, London, Memoirs, **20,** 1006 pp.

[xl] Falk-Pedersen, O *et al*. (2007) Carbon Capture and Storage at Kårstø, Ed. Svendsen (for the Norwegian Water Resources and Energy Directorate, NVE).