Opportunities for CO_2 Storage around Scotland

—an integrated strategic research study

Scottish Centre for Carbon Storage

The Scottish Government
Riaghaltas na h-Alba

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Foreword

Rapid man-made climate change is the greatest environmental challenge facing us today. The principal human influence on our climate is emission of greenhouse gases, including CO_2, from our use of fossil fuels.

The Scottish Climate Change Bill will introduce ambitious legislation to reduce these greenhouse gas emissions by 80 per cent by 2050. This will highlight many challenges for Scotland, particularly in terms of addressing our future energy needs and in generating energy efficiently and sustainably in environmentally neutral ways. We will therefore have to adopt new thinking, new solutions, and new technologies, and this presents the opportunity to put Scotland at the forefront of building a sustainable low carbon economy.

A major contribution could be made by the capture and transport of CO_2 from power stations and large industrial sites, to storage in underground reservoirs offshore—thus demonstrating that this technology can play a key part in our sustainable energy future.

The Scottish Centre for Carbon Storage has brought together the expertise of a number of our leading scientists, engineers and technologists from a range of disciplines and organisations to address the potential for, and challenges associated with, carbon capture and storage in Scotland.

A key conclusion of the report is that Scotland has not only the storage capacity but also the geographical context and know-how to become a major hub for CO_2 transport and storage in Europe. Scotland is therefore uniquely placed to benefit from being an early adopter and, through its world class science and technology, to be amongst the leading nations involved in the study of carbon capture and storage, exporting skills and knowledge globally into what could become one of the world's largest energy markets.

This is the most comprehensive study of its type undertaken in the UK and I hope that the report will stimulate further debate on the way forward for Scotland, in terms of carbon capture and storage technologies.

Professor Anne Glover, Chief Scientific Adviser for Scotland.
April 2009.

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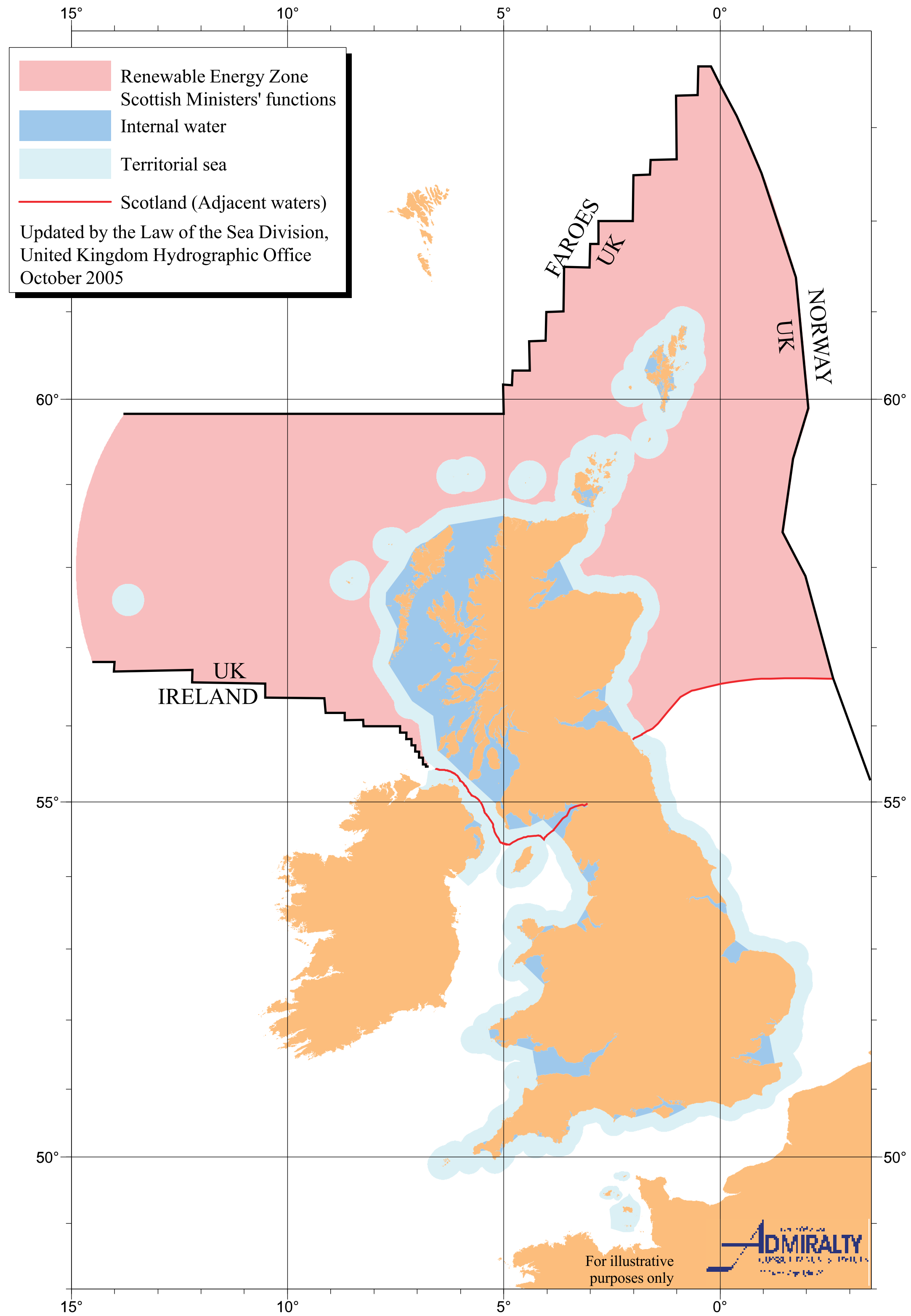


Executive summary

Carbon Capture and Storage (CCS) is one of the critical technologies worldwide which will enable reduction of carbon dioxide (CO_2) emissions arising from large industrial sites. CCS allows the continued use of a diverse mix of energy sources, including fossil fuels, which improves the security of cost-effective electricity supply. Scotland has the opportunity and responsibility to reduce CO_2 emissions arising from burning of fossil fuels and their impact on climate change.

The EU plans to have 12 CCS plants operating by 2015. In February 2009, the UK Secretary of State for Energy and Climate Change stated an aspiration for the UK to have more than one demonstration project in operation enabled by government funding. However, these targets cannot be delivered without the underpinning knowledge from studies such as this.

Commitment to large-scale investment in CO_2 capture plant will require proven storage capability.
This study

- presents the first high-level screening of CO_2 storage sites available to Scotland
- evaluates the means by which CO_2 can be transported from power plants and other industrial activities to storage sites, and
- investigates the costs and business constraints.

This is the most comprehensive and fully integrated study performed in the UK, and was achieved by a collaborative partnership of Scottish Government, research universities and institutes, and a broad base of support from industry and business.

The conclusions show that Scotland has an extremely large CO_2 storage resource. This is overwhelmingly in offshore saline aquifers (deeply buried porous sandstones filled with salt water) together with a few specific depleted hydrocarbon fields. The resource can easily accommodate the industrial CO_2 emissions from Scotland for the next 200 years. There is very likely to be sufficient storage to allow import of CO_2 from NE England, this equating to over 25% of future UK large industry and power CO_2 output. Preliminary indications are that Scotland's offshore CO_2 storage capacity is very important on a European scale, comparable with that of offshore Norway, and greater than Netherlands, Denmark and Germany combined.

CO_2 storage in oil fields may be feasible in conjunction with CO_2-Enhanced Oil Recovery (CO_2-EOR). If offshore pipelines reliably delivering CO_2 could be developed through demonstration projects, then an increased number of oilfields could become economic for EOR providing other critical factors such as oil price, additional oil recovery and infrastructure suitability are also favourable. Additional benefits include delayed decommissioning costs and extended benefit to the economy through development of technology and expertise in offshore CO_2-EOR. However, contrary to many expectations, this study has shown that most oilfields in the northern North Sea cannot easily be used solely for CO_2 storage because sea water injection, commonly used to maintain field pressure during oil production, significantly reduces the amount of storage capacity for CO_2.

Pipelines are the best option for the secure and continuous transport of millions of tonnes of CO_2 from different CO_2 sources to collection hubs onshore and then to offshore storage hubs for local distribution to diverse storage sites. Several routing options exist and, importantly, can include the connection of pipelines carrying CO_2 originating from England or continental Europe. Capital and operational costs for CCS projects are similar to those of the hydrocarbon industry.

Electricity generated in Scotland from power plant fitted with CCS is shown by this study to be comparable in price to that generated from other low-carbon technologies. The cost of abatement per tonne of CO_2 is cheaper on coal plants than on gas, because coal produces larger amounts of CO_2 per unit of electricity. However, the cost per unit of low-carbon electricity from coal and gas CCS is approximately the same.

The key conclusions of the study are:

1. The amount of CO_2 produced from industrial sources within Scotland is about a tenth of that of the UK as a whole. Without CCS, Scotland is likely to produce between 300 and 700 million tonnes of CO_2 from 2010 to 2050— that is, on average, between 8 and 18 million tonnes per year (Mt/year) depending on the proportions and types of power generation. In 2006, CO_2 output from major industrial sources in NE England amounted to over 50 Mt/year.

2. Geological reservoirs suitable for storage of CO_2 are classified according to whether they contain (or have contained) oil, gas, or saline water. Saline aquifers have the largest storage potential but with uncertainties regarding storage capacity of individual sites. From a resource of more than 80 saline aquifers studied, ten have been identified with a total potential CO_2 capacity in the range 4,600 to 46,000 million tonnes — a capability to store more than 200 years of Scotland's CO_2 output from its major fixed industrial sources.

3. Initial costs of assessing potential saline aquifer stores are likely to be considerably higher than for oil and gas fields which have previously been fully evaluated during many years of both exploration and production operations. Only detailed appraisal studies that include drilling of boreholes are likely to provide sufficient confidence to initiate a commercial-scale CCS project. Thus, pilot CO_2 capture projects will be an essential element of developing any new CO_2 storage site.

4. From a resource of more than 200 hydrocarbon fields, 29 have been identified as clearly having potential for CO_2 storage. Four gas condensate fields and one gas field offer significant potential for CO_2 storage. However, most of the oil fields can only be used as CO_2 stores in conjunction with CO_2-EOR technology.

5. CO_2-EOR may act as a stimulus for CCS especially if developers come to expect that the price of oil will remain over US$100 per barrel for the period of their investment. Development of a CCS infrastructure in Scotland could lead to application of CO_2-EOR (and, therefore, additional oil production and revenue) in certain fields.

6. Storage hubs are proposed to give multiple storage options within a geographical area to reduce costs and risks to CCS infrastructure. A pipeline network would be used to transport 20 million tonnes/ year of CO_2 from sources to distribution hubs offshore. Capital costs are £0.7 to £1.67 billion, depending on hub location. The hubs are proposed to give multiple storage options within a geographical area to minimise costs and risks to CCS infrastructure. The preferred route is through an onshore pipeline from the Firth of Forth to St Fergus, then onwards to an offshore storage hub, while an offshore pipeline route from the Firth of Forth should also be considered. Transport of additional CO_2 from NE England is best served by a pipeline direct to an offshore storage hub. Ship transport is possible as an interim solution, ideally discharged at the offshore hub.

7. A phased approach is appropriate to support the development of CCS technology. Direct Government funding will be required in the short term for R&D and pilot projects. In the medium term, CCS demonstration projects required under the UK Government and EU programmes, will need income support. Other low-carbon technologies, such as renewable power generation, currently receive incentives which are envisaged to continue for the medium term. In the long term, low-carbon generation projects are capable of being supported by the price of carbon alone. However, the volatility of the carbon market will place an additional financial risk on such projects.

8. The long term carbon abatement cost of CCS coal and CCS gas appear comparable with other available low-carbon power generation technologies and CCS has the potential to materially contribute to carbon abatement in Scotland.

The way forward

Scotland has the potential to become a significant player in the CCS industry both in its practical application, using its significant offshore resource, and in the development of exportable technology and skills. However, having examined

- the levels of funding required
- the levels of risk
- the regulatory structures
- and potential business models

the study has concluded that CCS will not commence without significant Government support and initial funding, similar to that required to develop low carbon wind and marine technologies. This strategic study has identified key initiatives that need to be acted upon to move CCS forward in Scotland.

1. There is a need for more detailed evaluation of Scotland's offshore storage sites. Saline aquifers represent the major CO_2 storage opportunity. For these to be the basis of viable CCS projects there is a need for detailed mapping and evaluation of specific saline aquifers, akin to that undertaken by the oil industry assessing hydrocarbon prospects prior to exploratory drilling. Early assessment will greatly speed-up the development of viable CCS projects.

2. If CCS projects are to make progress in the short term, there is a need for direct Government assistance to support R&D activity, which can prove the availability of storage in offshore saline aquifers and gas fields. If sufficient storage capacity offshore Scotland is proven, then EU-sized transport and storage industries can develop. In the medium term, income support estimated at £100 M/year is required per project to construct and operate the number of large projects envisaged in the UK and the EU. This will reduce if the carbon market price reaches stability at a commercially attractive level, and make CCS a long-term profitable option.

3. New alliances of businesses are needed to deliver CCS as early demonstration projects will face uncertainties of cost, technical operation and income. These first demonstrator projects are essential to start a process of learning, improvement, and cost reduction. No UK CCS will develop until these demonstrators are implemented and evaluated.

4. At high oil prices CO_2-EOR may lower the overall level of support required for early CCS demonstration projects, provide incentives for industry development and add volume to Scotland's hydrocarbon reserves. Projects to assess the viability of CO_2-EOR in specific oil fields or clusters of oil fields could therefore be important.

5. A CCS transport infrastructure is essential to connect sources with stores. Subject to suitability, existing pipeline networks may be exploited to varying degrees within the context of early pilot operations through to industrial scale demonstration projects.

6. Political and public support is crucial for progressing CCS. Public investment is likely to be required, initially at least, to ensure that the infrastructures are established and the private sector receives sufficient incentive to establish demonstration projects and to develop the technologies. To reduce the financial uncertainty to acceptable levels, additional monetary support is needed, as is given to renewable power generation.

7. The successful development of CCS in Scotland requires an assessment of the existing diverse skills base to identify where we need to build expertise. Academia and industry, working with the Scottish Government, can then address these issues.

8. Initiate an environmental assessment that will engage the relevant agencies and allow early consideration of the environmental issues associated with the deployment of CCS.

Aerial view of Longannet Power Station. Courtesy of ScottishPower.

1| Introduction

This document reports the results and recommendations of a study of the key issues bearing on the development and deployment of Carbon Capture and Storage (CCS) technology in Scotland. It was funded by the Scottish Government and industry, and was conducted by the Scottish Centre for Carbon Storage in cooperation with key industry participants.

The key issues are:

- identifying and assessing potential carbon storage sites in Scotland
- appraising Scottish infrastructure and the costs of developing it to enable CCS projects
- understanding the regulatory environment for CCS
- understanding the economics of CCS projects.

This study has:

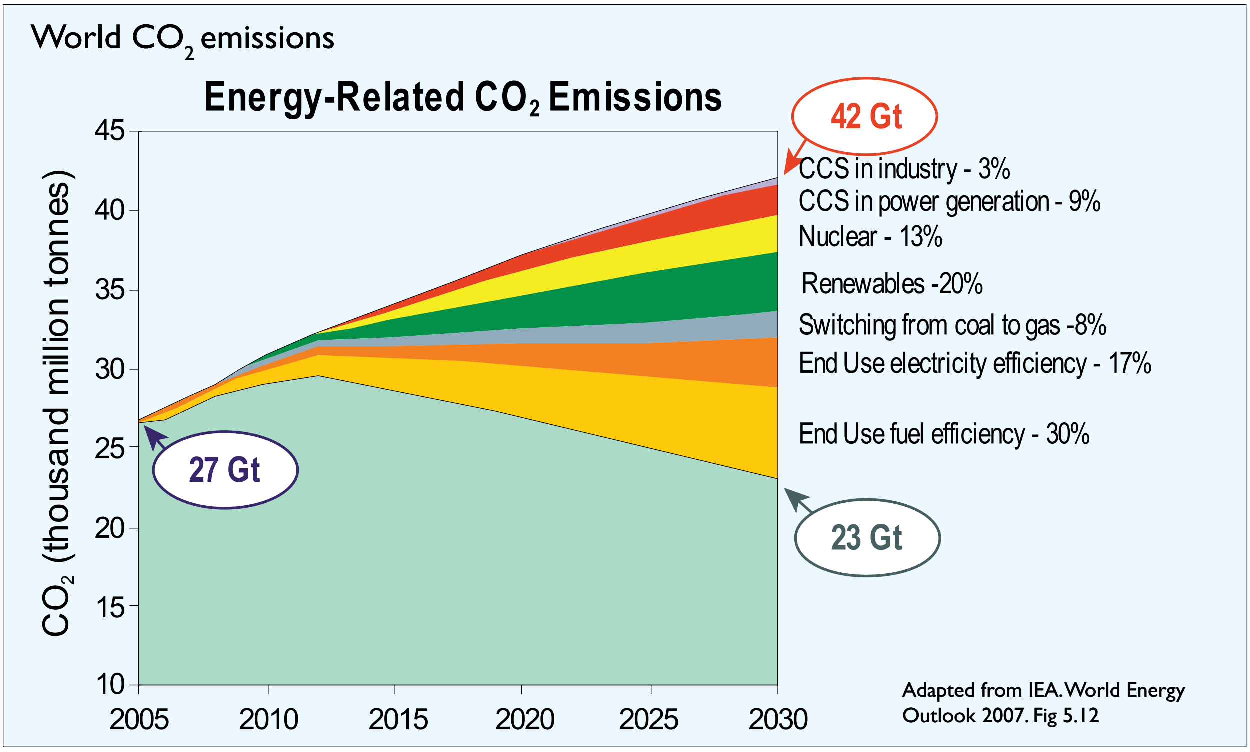
- identified the principal sources of carbon dioxide (CO_2) that could be captured and stored (that is, power generation and major fixed industrial plants) throughout Scotland and NE England and modelled their likely future emissions
- screened potential CO_2 storage sites to identify those that are likely to be safe and commercially and technically viable
- examined the economics and practicality of enhanced oil recovery using CO_2 in North Sea oil fields
- developed a high-level model for a transport network capable of taking CO_2 from these sources to offshore CO_2 storage sites
- examined current and future regulations that may affect CCS
- identified gaps between the current commercial/fiscal conditions and those required to make CCS commercially viable
- created the evidence base and economic models required to support informed decisions regarding the early development of CCS infrastructure in Scotland
- established the further steps necessary to make large scale CCS in Scotland a reality.

The results of this strategic study have been derived from scientific literature, data from a variety of governmental organisations, and calculations and conclusions generated within the study itself.

It is now established that man-made emissions of carbon dioxide (CO_2) are a major contributor to climate change. Carbon Capture and Storage (CCS) has the potential to enable very large reductions in CO_2 emissions arising from major industrial sources such as the generation of electricity. CCS is one of several possible options for reducing the rate of build-up of CO_2 in the atmosphere and should be seen as forming part of an overall CO_2 mitigation strategy.

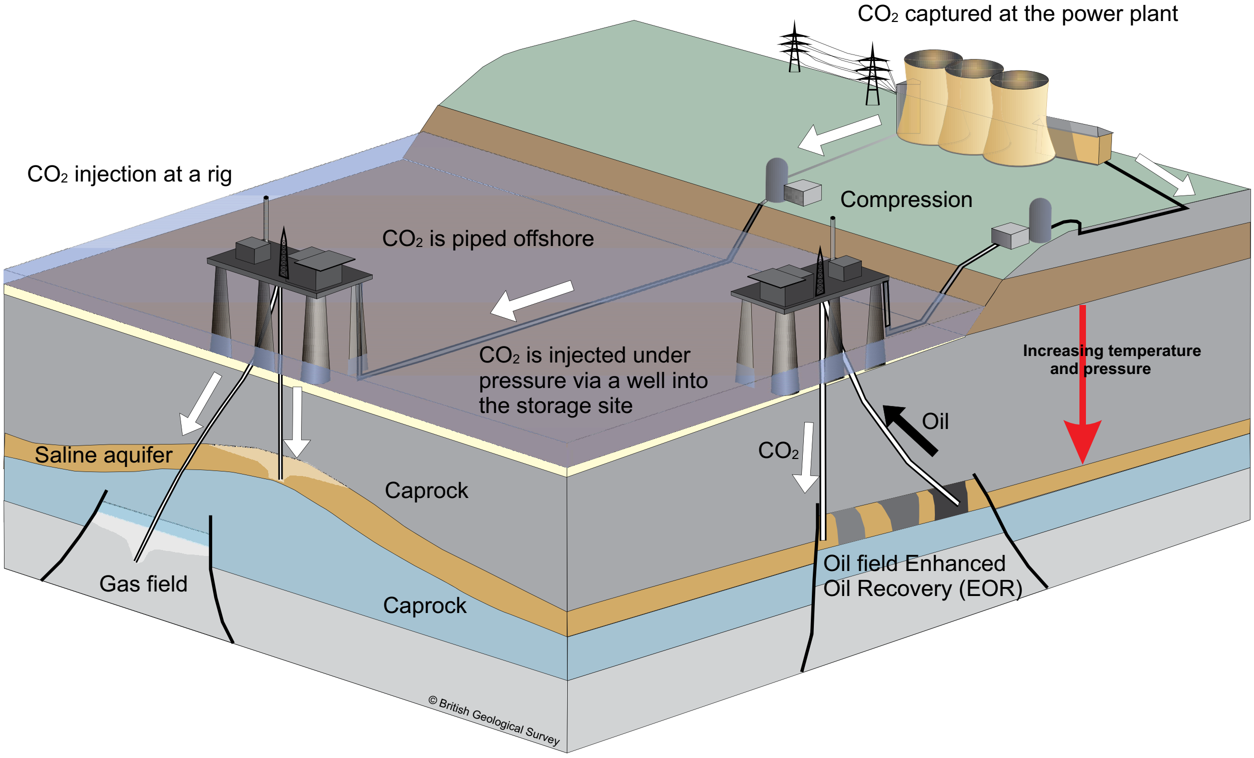
This can be illustrated using stabilisation 'wedges' where each wedge represents a strategy to reduce CO_2 emissions (Figure 1). The thickening of each wedge reflects take up of the particular CO_2 reducing initiative.

Figure 1
Wedge diagram illustrating proportions of different initiatives required to reduce CO_2 concentration in the atmosphere.



CCS comprises a set of technologies that together enable CO_2 to be captured from industrial point sources, be processed, transported via pipelines (or ships in certain cases) and injected into deep rock formations at 1000 to 2500 m below the Earth's surface (Figure 2). At present, a small number of CCS projects have been initiated within the UK and the EU but as yet there are none within UK waters of the North Sea. For instance, there are two projects operating within Norwegian waters, one at the Sleipner Field in the Norwegian sector of the northern North Sea, the other at the Snøhvit Field offshore northern Norway which transports CO_2 via a 150 km pipeline to a subsea injection location. There is also a small scale injection test being undertaken at the K12B Gas field offshore Netherlands.

Figure 2
Schematic showing elements of CCS infrastructure and relationship with geological structure.



Although a gas at the Earth's surface, carbon dioxide takes a very different physical form under only slightly changed conditions. Most people are familiar with the cold, solid form known as 'dry ice' that CO_2 takes when frozen. By contrast, when placed under moderate pressure (73.7 bar or greater), and warmed (to greater than 31.1°C), it becomes a dense fluid with properties of both a liquid (density) and a gas (viscosity). In this form, CO_2 occupies one hundredth of the volume it does as a gas. Nevertheless, liquid CO_2 (density 0.7 g/cm^3) is less dense than water (1.0 g/cm^3) and like oil will float upon water. Thus some form of physical containment is needed to prevent upward migration and leakage in a subsurface store, and the physics of liquid CO_2 therefore place depth and temperature, as well as geological, constraints on any potential storage reservoir (Figure 2). In this dense state, CO_2 is readily and efficiently transported by pipeline, as it flows like gas.

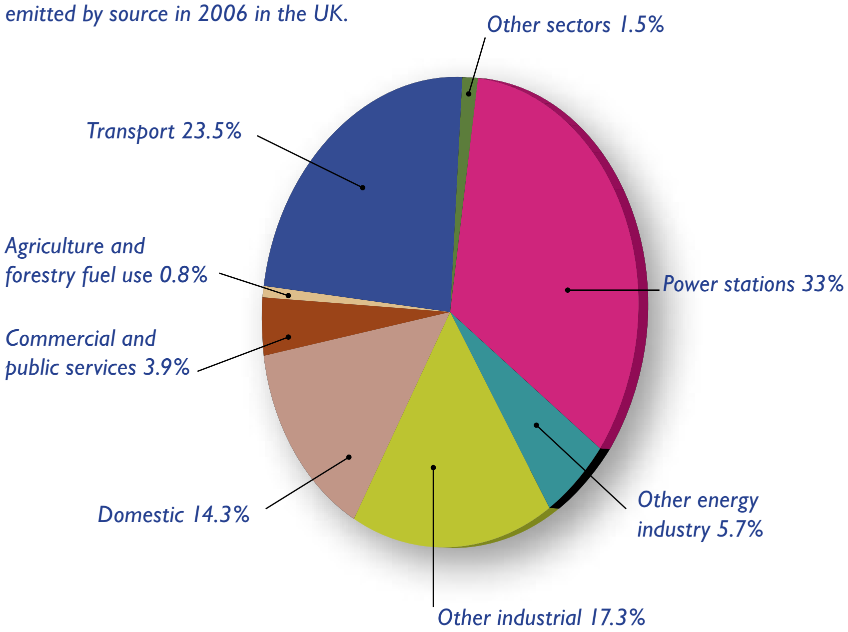
Choice of study area

The extent of the study area is shown by the limits of the Scottish Renewable Energy Zone which spans onshore Scotland and extends to offshore areas and is defined in ***The Renewable Energy Zone (Designation of Area) (Scottish Ministers) Order 2005***, *ISBN 0110736176* (see map facing Contents page). Although this limit excludes a large number of potential carbon dioxide storage sites it defines an area covered by Scottish environmental statutes and as such lies within a legally defined area. Competition and/or co-operation with other potential carbon dioxide storage sites outwith the area defined in this study is possible but was not considered in detail in this study. The study focussed on the offshore area to the east of Scotland as this is closest to the major Scottish and northern English CO_2 sources. The geological formations with the greatest potential for storage of CO_2 are located offshore and include a large number of hydrocarbon fields and saline aquifers and the data to enable meaningful assessment.

Part of the Sleipner Field CCS infrastructure, offshore Norway. Courtesy of StatoilHydro.

2| CO_2 sources

Figure 3
Relative proportions of CO_2 emitted by source in 2006 in the UK.



In this section, the principal industrial sources of CO_2 (power generation and industrial plant) in Scotland and NE England are identified, and the levels of output for sources in Scotland during 2006 are quantified. Likely levels of CO_2 output are then estimated for 2020, 2030 and 2040 by considering various energy generation mixes. This information is used to quantify CO_2 storage and transport requirements and to plan a network infrastructure that will respond to these requirements.

Scotland's total CO_2 emissions in 2006 were estimated to be 44 Mt, around 8% of the total UK emissions of approximately 557 Mt. The majority of the large fixed sources of CO_2 are power generation plants, which give rise to 33% (~184 Mt) of the UK total; integrated steel plants and the larger oil refinery/petrochemical complexes are further significant sources. Of the remaining sources of emissions, the largest single contribution was from transport (23.5%) (Figure 3).

All the major energy generators and industrial point sources of CO_2 in England, Wales and Scotland that emit more than 10,000 tonnes of CO_2 per year report this output to the National Atmospheric Emissions Inventory (NAEI) and the Scottish Environmental Protection Agency (SEPA) (Figure 4).

Figure 4
Location of industrial sources of CO_2 emissions in Scotland and NE England that emitted more than 100,000 tonnes per year in 2006.

In 2006, approximately 18 Mt of CO_2 (around 41% of Scotland's total carbon emissions) was produced by Scotland's three largest power stations. The output of Longannet alone is approximately 10 Mt. A combined total of 71 Mt of CO_2 (~24% of total UK fixed industrial) was produced by the top ten sites in Scotland and NE England (Figures 4 and 5).

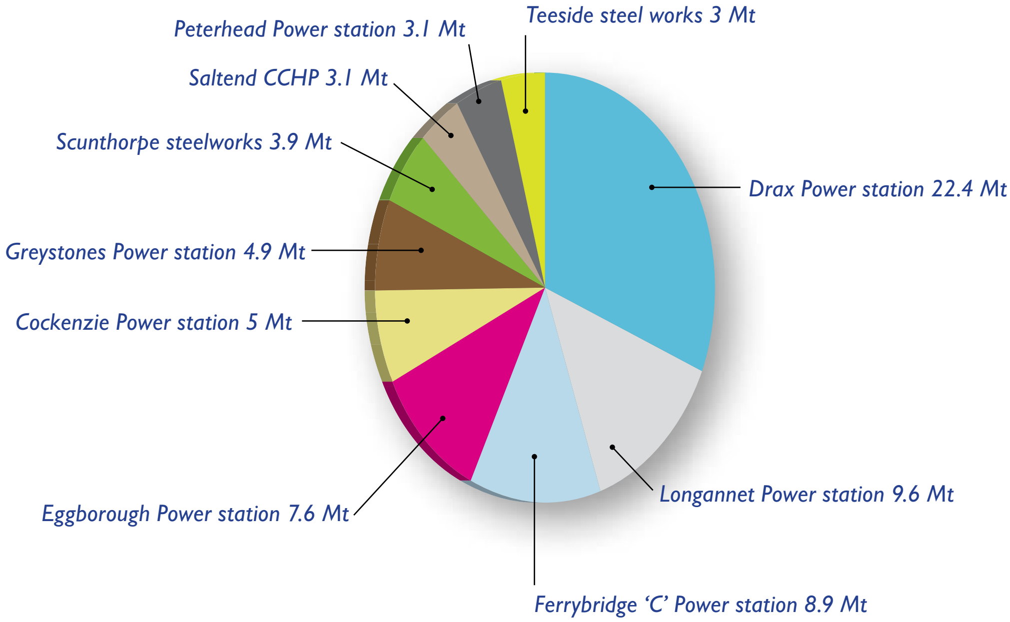


Figure 5
Top ten CO_2 sources in Scotland and northern England in 2006.

For Scotland, the amount of CO_2 produced in the future will largely depend upon the method of energy generation and the relative proportions of types of energy supplied. Likely levels of CO_2 production were considered for 2010, 2020, 2030 and 2040. For 2010, it was assumed there would be little change in output from figures provided for 2006 (Figure 5). A range of scenarios for CO_2 production in 2020, 2030 and 2040 is summarised below (Figures 6, 7 and 8). For each of these years, different energy mixes were analysed, with no judgement as to which scenario was more likely, and a range of possibilities presented. (Tables 1, 2 and 3). The scenarios yield high, medium or low CO_2 output reflecting the different energy mixes. The examples shown in Figures 6, 7 and 8 assume that carbon capture technology is not installed. Note that if carbon capture equipment were installed, gross (prior to capture and storage) CO_2 output would be higher, by between approximately 12% (CCS mature) and 25% (CCS immature) reflecting the additional energy required to extract the CO_2 and purify it. However, the extra CO_2 produced by the carbon capture process will, by definition, be captured as part of this process and should not result in additional CO_2 being released into the atmosphere.

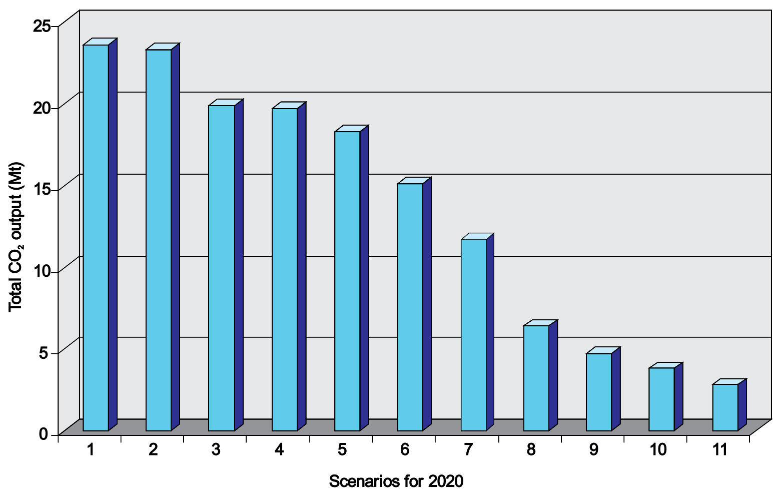


Figure 6
CO_2 output at 2020 for 11 Scottish scenarios.

Table 1
Proportions of different energy generation methods for each of the 11 scenarios possible for 2020.

Energy mix	Renewables %	Nuclear %	Coal %	Gas %	CO_2 output Mt
1	30	15	45	10	23.6
2	30	0	35	35	23.3
3	40	0	30	30	19.9
4	50	0	35	15	19.7
5	30	15	27.5	27.5	18.3
6	40	15	22.5	22.5	15.1
7	50	15	17.5	17.5	11.7
8	30	35	0	35	6.4
9	40	35	0	25	4.7
10	65	15	0	20	3.8
11	50	35	0	15	2.8

Figure 7
CO_2 output at 2030 for 6 Scottish scenarios.

For 2030, CO_2 production was calculated on the basis of electricity demand as at present. Calculations assuming a year on year 1% increase of electricity demand from 2020 to 2030 were also carried out but did not change the ranking of energy mix scenarios.

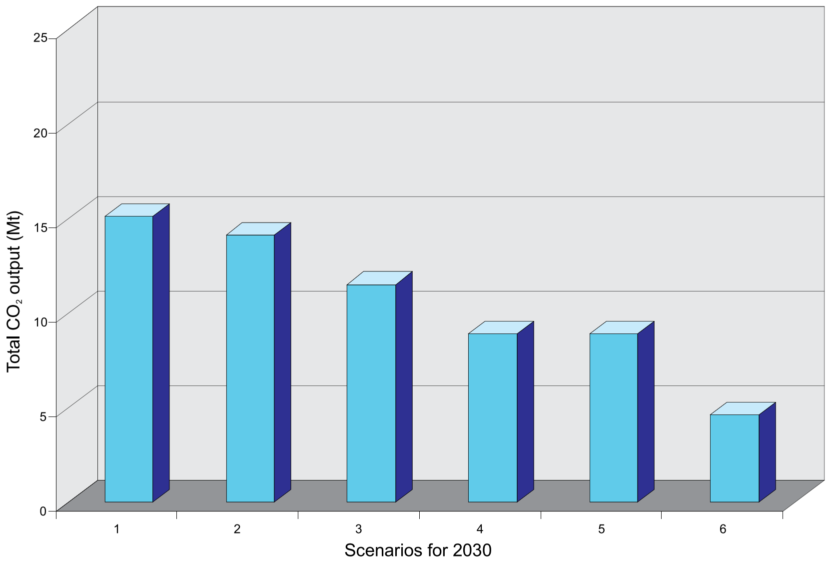


Table 2
Proportions of different energy generation methods for each of the 6 scenarios possible for 2030.

Energy mix	Renewables %	Nuclear %	Coal %	Gas %	CO_2 output Mt
1	40	0	30	30	15.1
2	50	0	35	15	14.1
3	40	15	22.5	22.5	11.5
4	50	15	17.5	17.5	8.9
5	30	35	17.5	17.5	8.9
6	40	35	0	25	4.6

For 2040, CO_2 production was calculated on the basis of electricity demand as at present. Calculations assuming a year on year 1% increase in electricity demand from 2030 to 2040 were also carried out but did not change the ranking of energy mix scenarios.

Figure 8
CO_2 output at 2040 for 12 Scottish scenarios.

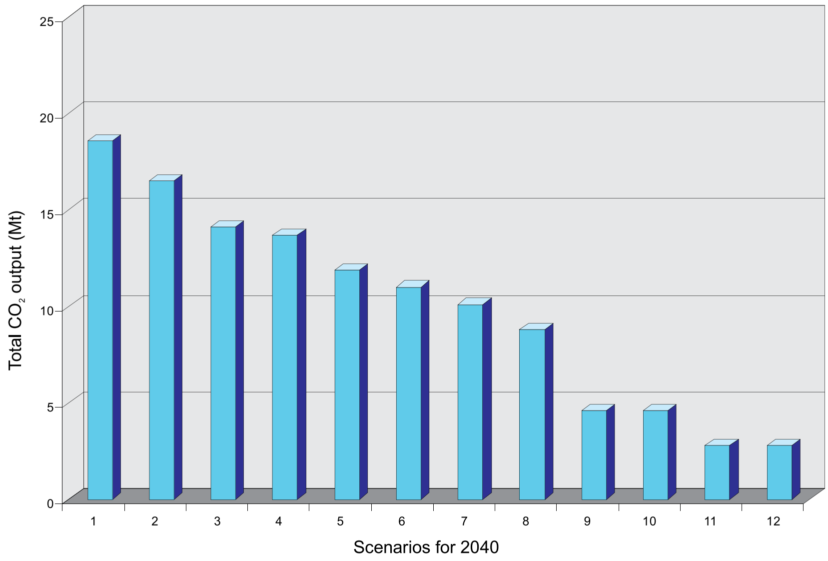


Table 3
Proportions of different energy generation methods for each of the 12 scenarios possible for 2040.

Energy mix	Renewables %	Nuclear %	Coal %	Gas %	CO_2 output Mt
1	40	0	55	5	18.6
2	40	0	40	20	16.5
3	50	0	35	15	14.1
4	40	0	20	40	13.7
5	50	0	20	30	11.9
6	40	15	20	25	11
7	60	0	20	20	10.1
8	50	15	17.5	17.5	8.8
9	40	35	0	25	4.6
10	60	15	0	25	4.6
11	50	35	0	15	2.8
12	60	25	0	15	2.8

CO_2 Sources–key conclusions

For Scotland over a 40-year period from 2010 to 2050, total output from electricity generation alone will produce CO_2 outputs of:

- ~ 700 Mt or 17.5 Mt/year under a high CO_2-output scenario;
- ~ 320 Mt or 8 Mt/year under a low CO_2-output scenario assuming no nuclear power.

Additional major sources in NE England produced ~50 Mt CO_2 in 2006. Thus, if outputs from both regions are included, over the period to 2050, up to 3000 Mt CO_2 is potentially available for capture and storage. This is equivalent to 75 Mt CO_2 per year taking this high-case scenario.

3| CO_2 storage sites

To establish whether the Scottish offshore area has the potential for storing the amounts of CO_2 captured, the study identified and assessed potential CO_2 storage sites in the offshore area in terms of their relative storage capacities and geotechnical criteria.

Potential CO_2 storage sites in the offshore area are:

- saline aquifers and;
- hydrocarbon fields.

Hydrocarbon fields have, by definition, the proven ability to trap migrating gas and oil in suitable 'reservoir' rock for many millions of years. Hydrocarbon fields that may be suitable for CO_2 storage are

- those that either have ceased production, or will do so within the period covered by the study, or
- those that are suitable for enhanced oil recovery using CO_2 (CO_2-EOR).

Only a relatively small proportion of reservoirs contain hydrocarbon accumulations; the vast majority of potential reservoir rocks (typically sandstone in the North Sea) are filled with saline water, and these are known as saline aquifers.

Common to all types of storage site, the key metrics for assessing a potential site are:

- location;
- data availability;
- storage capacity;
- geotechnical characteristics of the storage site;
- timing of storage site availability.

3.1 Location

The area defined by the Scottish Renewable Energy Zone offshore has been examined (see map facing Contents page). It contains approximately 204 hydrocarbon fields (comprising 163 oil, 30 gas condensate and 11 gas fields) and 80 saline aquifers that might be suitable for the storage of CO_2. These numbers may increase in future as further hydrocarbon fields or saline aquifers may yet be discovered.

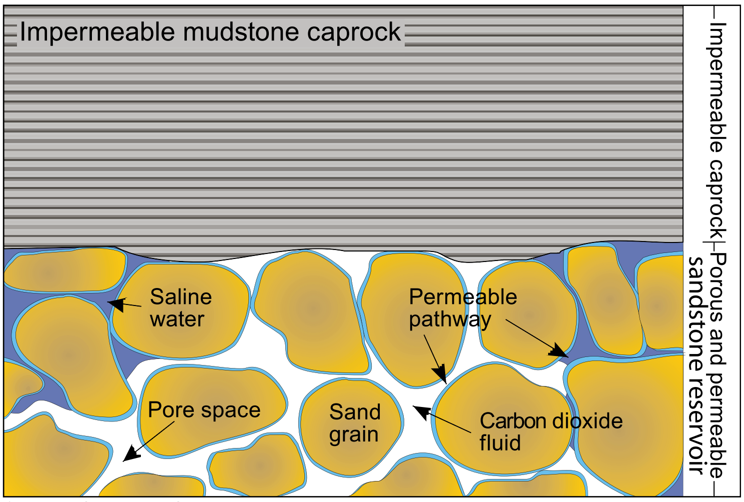
3.2 Data availability

Eighty (40%) of the known hydrocarbon fields and twenty-one (26%) of known saline aquifers were not screened and assessed because of various issues such as lack of readily available data, confidentiality, time or budget (Figures 11 and 12). Many of these sites could be suitable for CO_2 storage. Nevertheless, the storage sites remaining are considered to be representative of the whole area and include a large proportion of the potentially available capacity. Additional data from companies and government may well augment this list of potential storage sites as well as improve our understanding of those already identified.

3.3 Storage capacity and suitability

The CO_2 storage capacity of a hydrocarbon field or saline aquifer depends upon several factors. The **total volume of the storage reservoir** is relatively straightforward to determine, provided appropriate data is available. At a microscopic scale, reservoir rocks (for example, sandstones) contain spaces (between sand grains) within which fluids can be stored, or through which fluids can pass (Figure 9). The proportion of the total volume available for fluids is its 'porosity', and the ease with which fluids can pass through rock is described by its 'permeability'.

Figure 9
Cartoon illustrating porosity and permeability within the reservoir volume.



These spaces are filled with either hydrocarbons (oil, gas or gas condensate) or saline water. These fluids are all pressurised to a certain degree and must be displaced to allow storage space for CO_2. Thus, it is important to distinguish whether a reservoir is in 'open' pressure communication with surrounding rocks or whether it is 'closed'.

For **oil fields** not in pressure communication (closed), water is often injected to pressurise the reservoir and produce oil. Once production has ceased, much of the oil has been replaced by water but the reservoir may still be under high pressure. CO_2 injection will cause further pressurisation. This places significant limits on the amount of CO_2 that can be stored in this type of reservoir, since excessive pressure may ultimately cause fracturing of the caprock. The capacity available for CO_2 can be increased by permitting further fluid production, either of additional oil or of the water previously injected which would require clean-up by extracting oil to meet current environmental standards prior to discharge to sea.

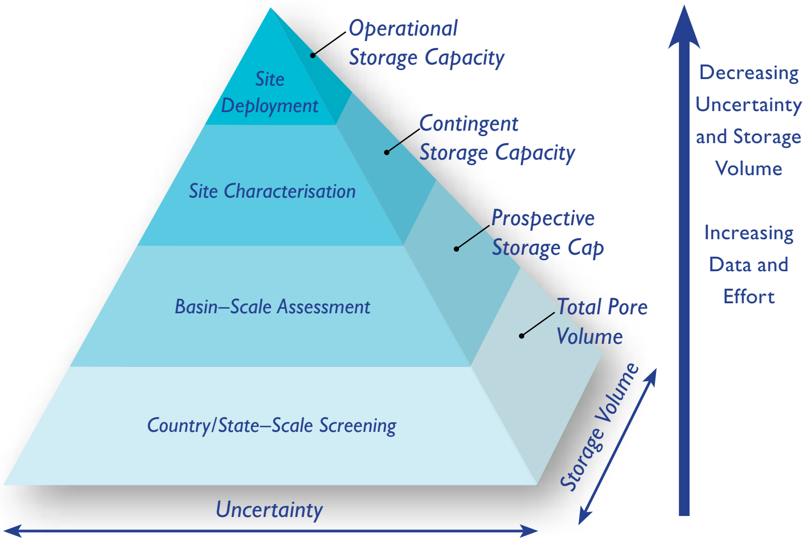
For **gas and gas condensate fields** the situation is different (even if closed) as production is usually driven by expansion of the gas without the need for water injection to maintain pressure. Thus pressure is likely to be very low by the time these fields become ready for CO_2 storage.

For **'closed' saline aquifers** pressure will again be the significant limiting factor. This was confirmed by numerical modelling carried out for this study and summarised later in this report (Section 5). Water production may be required to control pressure increase.

CO_2 injected into 'open' reservoirs is accommodated by lateral displacement of the existing fluids, and gives rise to minimal, local changes in pressure. The storage capacity of **'open' saline aquifers** is limited by how well the CO_2 displaces the saline water (its 'sweep efficiency'), the proportion of the saline aquifer that is structurally closed (trapping the CO_2) and the amount of CO_2 retained during migration. **Open reservoirs offer better potential for CO_2 storage**.

For the purpose of this strategic study, **storage capacity** was calculated at a basin-wide scale. This provides a ranking of potential storage sites but not absolute capacities. The best estimate of storage capacity of each reservoir will be refined as assessment becomes more focused (Figure 10).

Figure 10
Storage pyramid illustrating different stages in CO_2 storage capacity assessment. This study takes the assessment to near the top of basin-scale.



Adapted from CSLF 2007 Storage Pyramid modified 2008 CO2CRC Storage Capacity Estimation

For hydrocarbon fields, this basin-scale assessment enabled a ranking of their storage capacity. Following this analysis, the 95 hydrocarbon fields of estimated capacity less than 50 Mt CO_2 were considered too small to be viable for CCS storage and so were not examined further (Figure 11). Note that stores with less than 50 Mt CO_2 storage capacity may have value as satellites to larger sites or as part of a pilot or smaller scale demonstration project. Pressure-related issues further constrain the possibilities of using oilfield reservoirs for CCS.

The majority of oil fields in the Scottish offshore area are 'closed' and would require significant production of fluids (mainly previously injected water) to enable secure injection of significant quantities of CO_2. This is unlikely to be practical except in combination with **enhanced oil recovery (CO_2-EOR)**. As part of this study, oil fields were assessed for their suitability for CO_2-EOR and this is detailed in the next section entitled 'CO_2–ENHANCED OIL RECOVERY' (Section 4).

The **Brent Oil Field** is a possible exception as pressure support has been withdrawn and water produced in order to drop the pressure and release the gas contained within the remaining oil. As a result, there may be a CO_2 storage opportunity once depressurisation is complete and production has ceased (Table 4).

For **gas and gas condensate fields**, fewer limitations due to pressure in the reservoir are likely to be present. In all the gas condensate fields listed, there is minimal water replacement on production of hydrocarbons. Consequently, a large proportion of the pore space will be available for CO_2 storage. However, three of the gas condensate fields, classified as High Pressure High Temperature (HPHT) fields, are likely to be too costly to develop as CO_2 stores. In the Frigg Gas Field, water is used to drive the gas and consequently a smaller proportion of the available pore space will be available for CO_2 storage (Table 4).

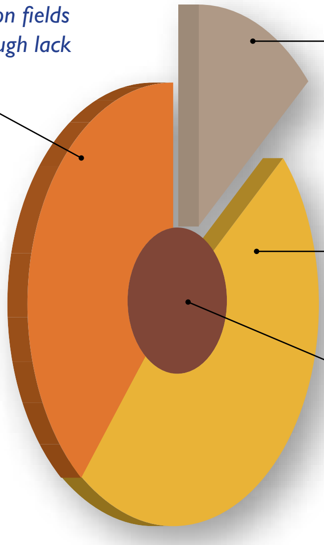


Figure 11
Numerical breakdown of the 204 Hydrocarbon fields identified within the study area showing proportion of fields taken forward for assessment.

In summary, basin-scale analysis was used to identify **29 hydrocarbon fields with apparent potential for CO_2 storage** (Figure 11). Of these, four gas condensate fields (Brae North, Brae East, Britannia and Bruce fields), one gas field (the Frigg Field, UK) and one oil field (the Brent Field) present the most obvious opportunities as stores (Table 4) with total CO_2 storage capacities of between 300 to 1000 Mt. The range of storage potential values reflects uncertainty with regard to assumptions in the calculation of storage capacity. The three HPHT gas condensate fields (Franklin, Elgin and Shearwater fields) are likely to be too expensive to develop as stores in the short term (Table 4). Fourteen oil fields, including the Brent Oil Field, have potential for CO_2 storage in conjunction with Enhanced Oil Recovery (see following section 4). The remaining seven oil fields offer large storage capacities but reservoir pressure issues may present obstacles to their use for CO_2 storage (Figure 13).

Table 4
Hydrocarbon fields assessed as having potential for CO_2 storage alone.

Field name	Vertical depth to crest (m)	Average Porosity (%)	Average Permeability (milli-Darcies)	Close of Production year	Average water depth (m)	Estimated CO_2–Storage (Mt)
Brae North GC	3633	15	300	2015	99	52
Franklin GC HPHT	5050	16	10	2030	93	62
Elgin GC HPHT	5300	17	25	2030	93	63
Shearwater GC HPHT	4700	Not available	Not available	2015	92	66
Brae East GC	3865	17	558	2020	116	111
Britannia GC	3597	15	60	2030	136	181
Bruce GC	3250	15	153	2020	122	197
Frigg (UK) Gas Field	1785	29	1500	2008	112	171
Brent Oil Field	2512	21	650	2015	140	456

Green—parameter is technically or economically favourable
Orange—parameter is technically or economically borderline
Red—parameter is technically or economically unfavourable
GC = Gas Condensate field
HPHT = High Pressure High Temperature field

Information about the properties of **saline aquifers** beneath the North Sea is less readily available than for hydrocarbons reservoirs. It was not feasible, within the constraints of this strategic assessment, to take into account the specific characteristics of individual saline aquifers. Instead, a generic figure for storage efficiency was derived from other regional studies and numerical modelling. Consequently, storage capacities for saline aquifers are given as ranges derived from storage efficiencies of 0.2% and 2% of pore volume (Table 6). Ten saline aquifers of storage capacity less than 50 Mt were excluded from detailed analysis (Figure 12).

3.4 Geotechnical characteristics of the storage site

Within the context of this strategic overview, geotechnical characteristics did not constitute immediate grounds for excluding any hydrocarbon fields since they have demonstrated that they are capable not merely of storing but of producing fluids. Nevertheless, these criteria have been flagged for each hydrocarbon field as this is useful information in any decision making process regarding suitability for CO_2 storage (Table 4). This is not necessarily the case for saline aquifers which were further screened using best practice geotechnical criteria (Table 5) categorised as green, meeting best practice requirements and orange, meeting minimum technical requirements (Table 5). The injection of CO_2 into a specific saline aquifer was investigated with the results detailed in the section entitled 'CO_2 INJECTION MODELLING WITHIN SALINE AQUIFERS' (Section 5).

Thirty-nine saline aquifers were excluded from further consideration because they do not meet minimum geotechnical requirements (Figure 12). **Ten saline aquifers** have therefore been identified as meeting both geotechnical (best, green and minimum, orange) and storage capacity requirements (Table 6).

Table 5
Summary of geotechnical screening criteria applied to saline aquifers.

Reservoir Attribute	Best practice requirements	Minimum technical requirements
Depth	>1000 m and < 2500 m	>800 m and <1000m
Permeability	> 500 mD	>200 mD and <500 mD
Porosity	> 20%	>10% and <20%

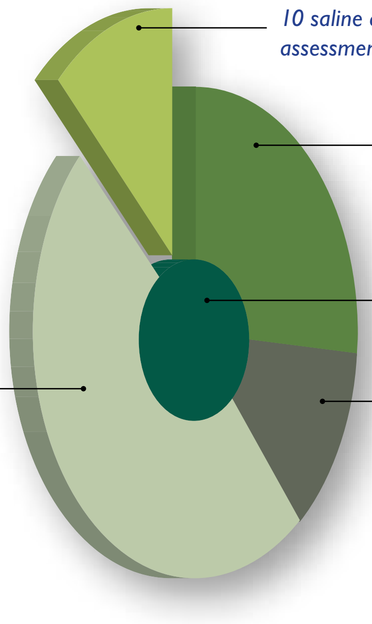


Figure 12
Numerical breakdown of the 80 saline aquifers identified within the study area showing proportion taken forward for assessment.

Table 6
Saline aquifers assessed as having potential for CO_2 storage showing the range of potential storage capacities calculated from storage efficiencies derived from regional studies and numerical modelling.

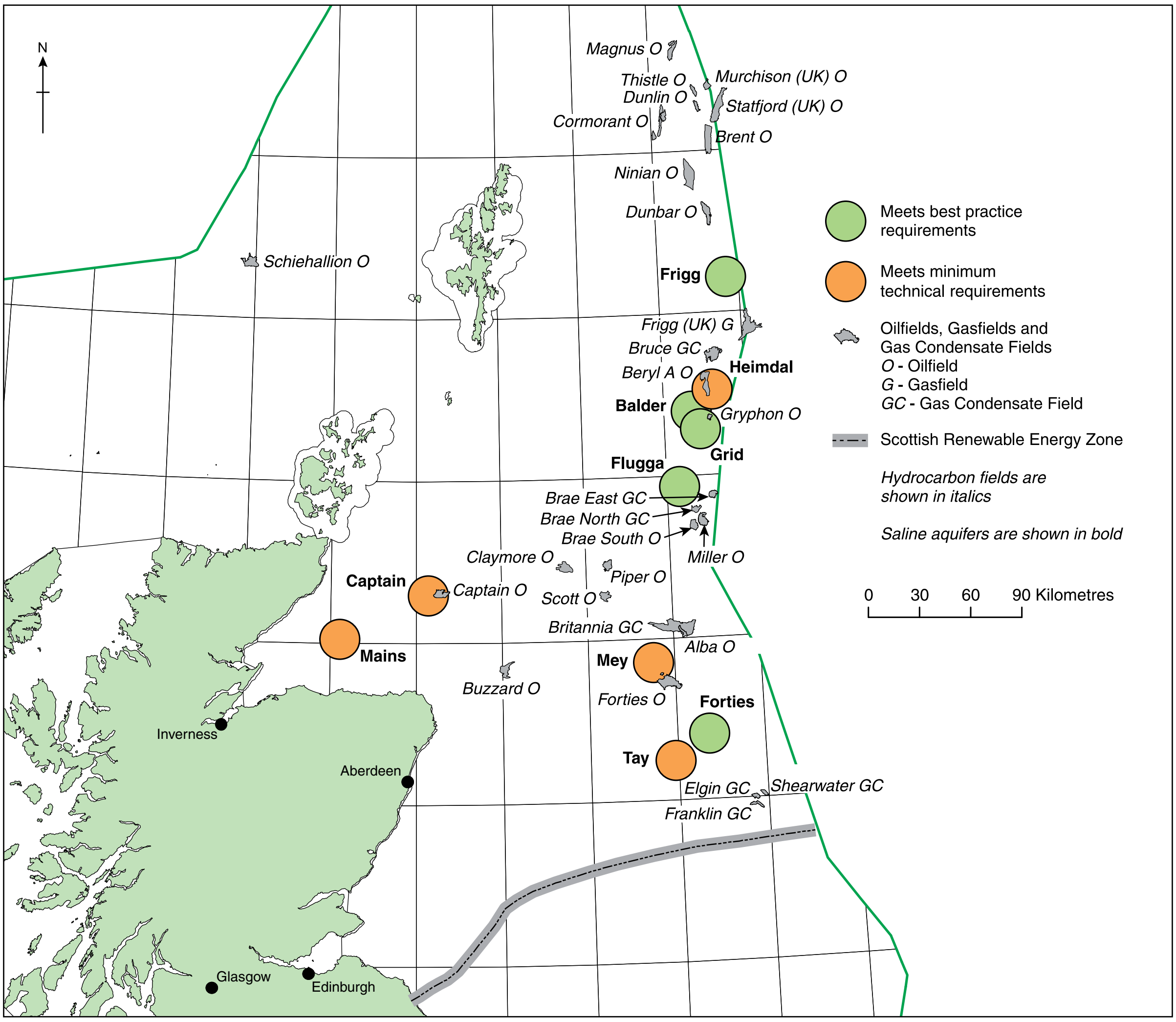
Saline aquifer	Area (km^2)	CO_2 storage capacity (Mt CO_2) assuming 0.2% storage efficiency	CO_2 storage capacity (Mt CO_2) assuming 2% storage efficiency
Forties	16069	886	8856
Grid	17147	785	7847
Balder	6251	347	3465
Flugga	1926	61	611
Frigg	1712	58	575
Mey	33190	1655	16549
Heimdal	11065	618	6177
Tay	2484	133	1328
Captain	3438	36	363
Mains	4601	24	241
Total CO_2 storage capacity (Mt)		4603	46012

3.5 Timing of storage site availability
As a practical working assumption, unless a hydrocarbon field is to undergo CO_2-EOR storage, CO_2 storage cannot begin until production ceases. **Close of production (CoP)** for all hydrocarbon fields was estimated from past production data (Table 4). For oil fields the CoP is of limited relevance, as use for storage without EOR is unlikely and CO_2-EOR will necessarily begin prior to the estimated closure date. It has been assumed that there are no timing restrictions governing the availability of saline aquifers, although exploration and appraisal of saline aquifers may take a number of years. One of the most pertinent issues for the development of a **CCS transportation pipeline** involving hydrocarbon stores is the matching of timing of CO_2 supply (from onshore sources) with available injection and storage capacity. Re-use of hydrocarbon production facilities may be an option in some cases. Historically, close of production forecast dates have tended to be unreliable, and depend on technology development, oil and gas prices, infrastructure lifetimes, and other market factors.

Oil & gas fields are currently better characterised in terms of both capacity and integrity than are saline aquifers so initially involve lower cost and risk. Without Enhanced Oil Recovery, oilfields offer limited capacity due to the past replacement of produced oil with water for pressure support. **Depleted gas and gas condensate fields offer good storage capability,** although there are relatively few in the Scottish Renewable Energy Zone. Storage of CO_2 in the offshore Scottish Renewable Energy zone is likely to be initially in depleted gas and gas condensate fields and in the few oil fields where pressure conditions are favourable, whilst long-term storage and the majority of storage capacity potential is likely to be in saline aquifers.

All 29 hydrocarbon fields and ten saline aquifers identified in this study as having the potential to store CO_2, either as part of an EOR project or purely as part of a CO_2 mitigation strategy are shown in Figure 13. The ten saline aquifers are colour coded according to whether they meet minimum or best practice geotechnical requirements (Table 5). They each have a unique size and shape, and the majority cover areas of several thousand square km. In some places, the saline aquifers overlap each other, being present at different depths at the same geographical location. The circles in Figure 13 denote their approximate central points.

Figure 13
The location of all 29 hydrocarbon fields and 10 saline aquifers identified as potential CO_2 storage sites within the Scottish offshore.



Risks and uncertainties are associated with all types of subsurface CO_2 storage reservoir, but with appropriate, storage site specific, appraisal it should be possible to reduce these to the level appropriate for business investment in and regulatory approval of a project typical of the oil and gas industry. It is likely that appraisal costs to reach this position will be higher for saline aquifers than for oil and gas fields, although saline aquifer capacity for storage is also likely to be correspondingly greater.

CO_2 storage sites–key conclusions

Basin-scale assessment has demonstrated

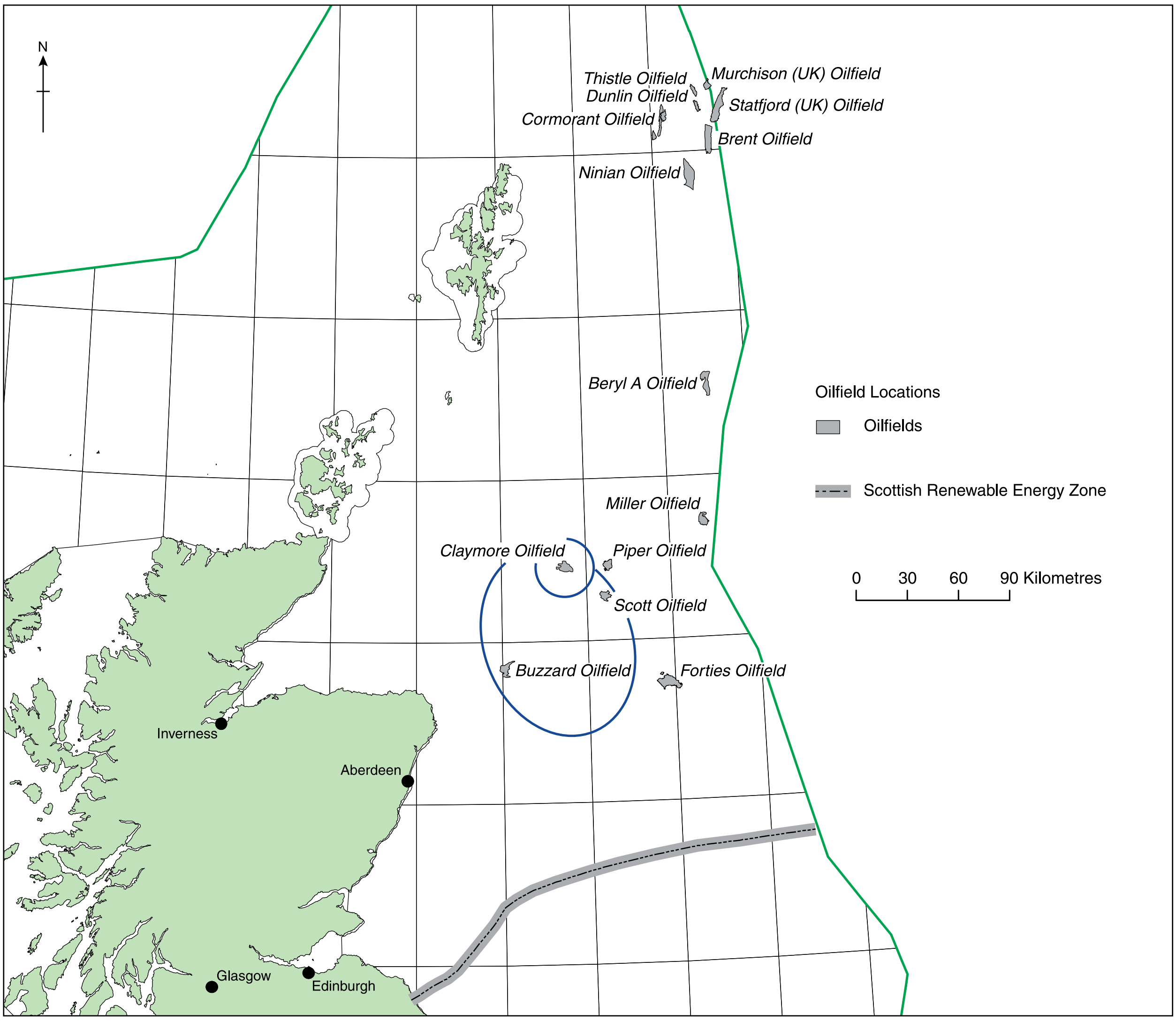
- From this first assessment, ten saline aquifers have been identified with a total CO_2 storage capacity of between approximately 4,600 and 46,000 Mt, providing a capability to store at least 200 years of Scotland's CO_2 output.
- Further study is necessary to fully scope saline aquifer storage potential.
- 29 hydrocarbon fields (21 oil, 7 gas condensate and one gas field) offer significant further CO_2 storage potential. Amongst these:
    - 8 Gas and gas condensate fields offer the best potential for storage;
    - Three high pressure high temperature gas condensate fields are unlikely to be used as storage sites due to prohibitive costs;
    - Oil fields are unlikely to be employed as CO_2 stores except in conjunction with Enhanced Oil Recovery;
    - The one remaining gas and four remaining gas condensate fields offer total ~700 Mt CO_2 storage potential;
    - Unusually, the Brent Oil Field offers an opportunity for CO_2 storage of ~400 Mt.
- The potential storage capacities as currently assessed are sufficient to provide an approximate ranking of sites in terms of their storage potential but sites need to be evaluated individually using more detailed models.

4| CO_2 — Enhanced Oil Recovery

The study assessed how enhanced oil recovery (EOR) by CO_2 flooding (CO_2-EOR) might either benefit from or be a benefit to CCS. It identified oil fields within the Scottish Renewable Energy Zone, in which CO_2-EOR was technically feasible, and a more detailed technical and economic assessment of a single field and field cluster was carried out (an exchange rate of $1.4/£ was used).

CO_2-EOR offers potential of economic gain through additional oil production as well as storage of the CO_2. On average, primary and secondary oil recovery by water flood from North Sea oilfields accounts for 45% to 55% of oil originally in place, although in some fields it has approached 70%. The residual oil is trapped as by-passed droplets in the rock pores or as a film on the rock grains and may occur as localised significantly higher saturation areas. EOR processes, employed as a third phase of oil field development, seek to **mobilise** this oil and move it in a 'bank' towards the production wells. However, CO_2-EOR is one of a number of competing 'Enhanced Recovery' techniques and to date has not been applied in the UK offshore.

Figure 14
Oil fields suitable for CO_2-EOR. Blue ovals show extent of detailed EOR study.



The majority of CO_2-EOR projects worldwide to date have been implemented onshore in **North American oilfields** since the 1970s and it is experience from these for which most relevant guidelines have been drawn up. No projects have yet been undertaken in the North Sea, although the Miller oilfield was recently considered for CO_2-EOR. Most existing North American projects have exploited natural CO_2 transported over extensive long-distance pipeline networks. Under these circumstances, an additional recovery of 5% to 15% of oil originally in place is typically achieved. The technique may not be as productive in North Sea oilfields, because secondary water flood recovery techniques are more widely applied, and wells are drilled further apart than on land.

A high level desk-top review of all oil fields with an estimated CO_2 storage capacity of >50 Mt was carried out to identify those **fields suitable for CO_2-EOR**. The 14 fields are shown in Figure 14 and their details are tabulated in Table 7.

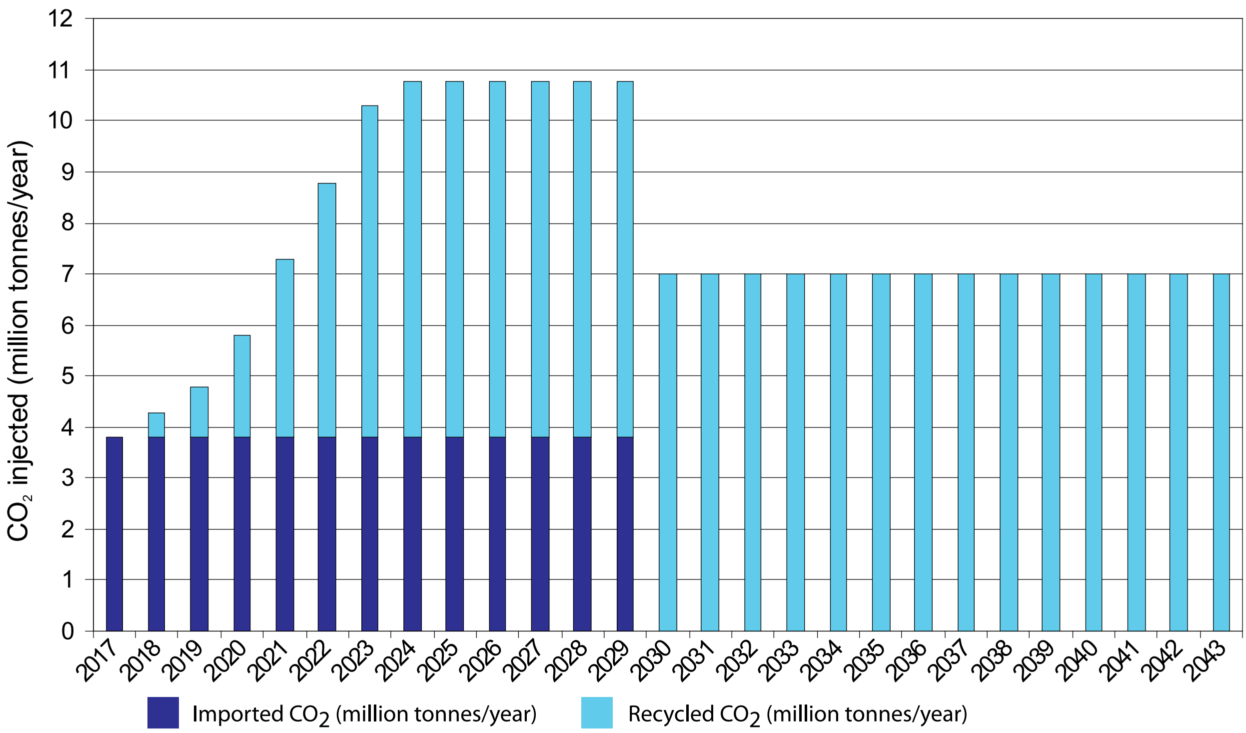
Table 7
Oilfields identified in a 'desk top' review as having potential for CO_2-EOR.

Field name	CO_2 storage capacity/Mt CO_2	Close of Production date	Potential for EOR		Projected additional oil recovered (million barrels)
Dunlin Oilfield	27	2015	Good		83
Thistle Oilfield	27	2015	Good		82
Claymore Oilfield (Central, Main and Northern)	47	2030	Good	OK	142
Cormorant Oilfield	52	2020	Good		157
Scott Oilfield	31	2015	Good		95
Statfjord (UK) Oilfield	209 (UK + Norway)	2020	Good		635 (UK + Norway)
Beryl A Oilfield	77	2020	Good		232
Ninian Oilfield	96	2030	Good		292
Brent Oilfield	165	2015	Good		501
Murchison (UK) Oilfield	26	2020	OK		79
Miller Oilfield	17	2008	OK		52
Buzzard Oilfield	36	2025	OK		108
Piper Oilfield	46	2030	OK		140
Forties Oilfield	138	2015	OK		420

To gain a more quantitative feel for the application of CO_2-EOR in North Sea oil fields, a technical and **economic assessment of a single large field**, the Claymore Field, was carried out (highlighted in Figure 14). Additionally, a 'cluster' of three large fields, Claymore, Scott and Buzzard (highlighted in Figure 14), were assessed as an 'integrated' CO_2-EOR project. In all cases CO_2-EOR was assumed to begin in 2017 (although Buzzard will not become available until 2023).

The oil in **Claymore** is contained in four separate reservoirs. The total oil initially in place was 1439 million barrels. For this study two possible scenarios were considered, a less likely scenario (30% probability) and a more likely scenario (70% probability) with the former yielding an optimistic and the latter a pessimistic recovery of additional oil. Starting in 2017, CO_2 would be injected at ~3.8 Mt/year with produced and recycled CO_2 eventually negating the capacity to take 'new' CO_2. Overall, the project would store 49.2 Mt CO_2 and produce between 119 and 163 million barrels of oil (Figure 15; Table 8).

Figure 15
Estimated CO_2 injection and recycle gas injection profiles for the Claymore Field.



Capital costs (CAPEX) are derived from the cost of converting existing facilities and the drilling and refurbishment of new and existing wells. Total capital investment is estimated to be around £1.1 to £1.2 billion. Operating and monitoring costs (OPEX) are estimated to be around £90 million per year.

Using an oil price of £50 (US$70) per barrel, and assuming that the project neither receives a subsidy nor pays for the CO_2 received, the **internal rate of return** is 12%–16% and the net present value at a 10% discount rate is £206–£703 million (lower and upper values correspond to the lower and upper values of additional oil recovered). All analysis is before tax and any benefit from deferral of abandonment of the facilities is not included.

Table 8
Claymore Field - additional oil production and CO_2 usage for 70% and 30% probability scenarios.
[*]amount of oil produced from CO_2 alone without contribution from associated waterflood.

70% probability scenario	Gross	Net*
Additional oil (million barrels)	164	119
CO_2 Injected (million tonnes)		49.2
CO_2 usage (tonne/barrel)		0.41
Recycle CO_2 (million tonnes)		151.5
30% probability scenario	Gross	Net*
Additional oil (million barrels)	208	163
CO_2 Injected (million tonnes)		49.2
CO_2 usage (tonne/barrel)		0.30
Recycle CO_2 (million tonnes)		151.5

Sensitivity (to CAPEX, OPEX, oil price and CO_2 price/subsidy) calculations on the discounted cash flow analyses showed that project economics were most sensitive to oil price, then CO_2 price/subsidy, then CAPEX, and relatively insensitive to OPEX. Although oil and CO_2 price are subject to market forces, this analysis showed that project economics can be improved considerably by refining the design and thereby reducing capital costs and risks associated with conversion of facilities and wells to CO_2 flooding.

4.1 Claymore, Scott and Buzzard cluster evaluation
An analysis of CO_2-EOR as an integrated project was carried out using the Claymore, Scott and Buzzard fields (highlighted in Figure 14).

The **Scott Field** has two oil reservoirs divided by faults into several isolated blocks. The field is significantly overpressured. Total oil originally in place was 946 million barrels. Note that the CO_2 use is much higher in Scott than for Claymore because of the significantly higher pressure in Scott and so higher CO_2 density (Table 9).

Table 9
Scott Field—additional oil production and CO_2 usage for 70% and 30% probability scenarios.

70% probability scenario	
Additional oil (million barrels)	71
CO_2 Injected (million tonnes)	52
CO_2 usage (tonne/barrel)	0.73
30% probability scenario	
Additional oil (million barrels)	101
CO_2 Injected (million tonnes)	52
CO_2 usage (tonne/barrel)	0.51

Capital costs for the Scott Field are estimated at £1.2 billion with operating costs, excluding tariffs, of around £45 million per year.

Buzzard is located in the Outer Moray Firth. Fluids are contained by a combination of structural and stratigraphical trapping. Total oil originally in place was 1077 million barrels, taken from published information. Forecasts have been downgraded by 40% in the economic analysis over concerns that the CO_2 may not mix with the oil in a way beneficial to the EOR process (Table 10).

Table 10
Buzzard Field—additional oil production and CO_2 usage for 70% and 30% probability scenarios.
** amount of oil produced from CO_2 alone without contribution from associated waterflood.*

70% probability scenario	Gross	Net*
Additional oil (million barrels)	85	79
CO_2 Injected (million tonnes)		46
CO_2 usage (tonne/barrel)		0.48
30% probability scenario	Gross	Net*
Additional oil (million barrels)	117	111
CO_2 Injected (million tonnes)		46
CO_2 usage (tonne/barrel)		0.41

The presence of facilities for dealing with **hydrogen sulphide or 'sour gas'** is likely to reduce the cost of adapting Buzzard to CO_2 injection so, for the purposes of this analysis the capital cost of conversion, is estimated at £700 million. The operating costs for Buzzard, excluding tariffs, are estimated at £55 million per year.

Aggregated results for this cluster of large fields give an **additional oil recovery** of 237–331 million barrels for around 155 Mt of CO_2 stored. The aggregated capital cost of the cluster redevelopment would be around £3.1 billion with **total operating costs** over the project lifetime of £2.6 billion. Using a £50 (US$70) per barrel oil price, and assuming that the project neither receives a subsidy nor pays for the CO_2 received, the internal rate of return is 13%–18% and the net present value at a 10% discount rate is £409–£1717 million.

The economics of exploiting CO_2-EOR in the northern North Sea have been examined in some detail. The combination of high capital requirements, high operating expense and relatively limited amounts of remaining oil gives rise to considerable sensitivity to both oil prices and the cost of CO_2 used for injection. CO_2-EOR may act as a stimulus for CCS especially if developers come to expect that the price of oil will remain over US$100 per barrel for the period of their investment. Higher oil prices would make CO_2-EOR projects more commercially viable and with that, the independent development of CCS. To date, the closest CCS has come to being realised in the UK is through a proposed CO_2-EOR project (Miller Field)—but the project was ahead of the political process and the field had to move to decommissioning before a government decision on policy support . However, development of CCS could lead to the application of EOR, since this reduces costs and uncertainties related to CO_2 supply.

Power stations will produce a fairly constant supply of CO_2 over many years. This study examined the CO_2 supply required for Enhanced Oil Recovery projects for a cluster of three large oil fields. Taking the three fields together, the supply of CO_2 required was substantial, approximately 11Mt/year for 13 years, and comparable to the output from a power station source.

CO_2-enhanced oil recovery–key conclusions

- Ignoring risk premiums, and if the CO_2 is not a cost to the project, CO_2-EOR may be economic in North Sea oil fields at an oil price of US$70 per barrel.
- If CO_2 is a cost to projects in the £20–£40 ($28–$56) per tonne range, an oil price of US$80–$110 per barrel will be required to break even.
- If a subsidy is available for the CO_2 stored then the project could be economic at an oil price significantly lower than US$70 per barrel.
- Taking risks into account, it is unlikely that CO_2-EOR will be commercially viable in North Sea fields at an oil price less than US$100 per barrel.
- The redevelopment of a mature North Sea field for CO_2-EOR is a major undertaking equivalent in complexity, scale and cost to the original development; each project will need to be the subject of detailed engineering design and economic appraisal including a full assessment of the risks.
- CO_2-EOR has never been applied offshore so early projects will carry significant additional financial risks.
- The total CO_2 storage capacity of all fields to which CO_2-EOR might be applied is ~1000 Mt.

5| CO_2 injection modelling within saline aquifers

In order to better understand how the available storage volume within a saline aquifer might be affected by injection of large amounts of CO_2 the Tay Sandstone saline aquifer (Figure 13) was selected for further study. Key issues governing whether large volumes of CO_2 can be safely, reliably and securely injected into and stored within a saline aquifer were investigated by modelling the injection of CO_2. The main areas of investigation were the potential of the saline aquifer to store the specified volumes of CO_2, the injectivity (including the number of wells required), the effect of orientation and location of wells, and the migration path of CO_2 away from the injection points. Sensitivity to injection rate, the number of wells, length, and spacing and location of wells were investigated. Two CO_2 injection scenarios were investigated addressing sources from Scotland and imported CO_2:

- a baseline case of 15 Mt/year
- a high-use case at 60 Mt/year.

5.1 Storage capacity of the Tay saline aquifer

Numerical modelling of the amount of CO_2 that can be stored in the Tay saline aquifer gives a wide range of possibilities according to whether the saline aquifer is considered 'open' or 'closed'. It is not yet clear which is the case. For this study, the Tay saline aquifer was modelled for both scenarios.

- **Tay saline aquifer open** (water naturally migrates out of the saline aquifer) —at an injection rate of 15 Mt/year for 25 years, the saline aquifer can readily store 375 Mt CO_2.
- **Tay saline aquifer closed** (water does not migrate out of the saline aquifer) —the saline aquifer can store 375 Mt CO_2 provided water is produced at a rate of 40,000–60,000 m^3/day. Without water production it can store only 155 Mt CO_2 (0.4% of total pore volume) because of the increase in pressure as the CO_2 is injected.

5.2 Investigation of sensitivities in modelling the saline aquifer

- Although the total volume of CO_2 injected at 15 Mt/year for 25 years injection is less than 1% of the total volume of water in the Tay formation, the **average reservoir pressure** increased 50% by the end of the injection period. The pressure then reduced gradually as the CO_2 dissolved in water.
- The **injectivity** of the Tay saline aquifer is very good, based on the reservoir properties collected from current oil fields.
    - Injection pressure varies with the porosity, permeability and the amount of reservoir rock.
    - To reduce pressure at the injector well, additional injectors are recommended for the 15 Mt/year plan. The injection rate for one well should be less than 6 Mt/year.
- Unless it is 'open', injection of 60 Mt/year CO_2 over 25 years into the Tay saline aquifer is likely to lead to **excessive pressure**.
- The **movement of CO_2** within the saline aquifer can be controlled by appropriate location of injector wells.
- Injected CO_2 tends to move higher within the reservoir, but when it dissolves in water it tends to move downwards.
- If producing hydrocarbon fields are connected to the saline aquifer, and CO_2 is injected into their vicinity, the CO_2 tends to move towards them, as they may be at a lower pressure than the saline aquifer, and are usually higher on the structure.
- The presence of a relatively impermeable layer within the saline aquifer did not act as a significant barrier to the lateral movement of CO_2.

6| CO_2 transport options between sources and storage sites

Successful implementation of CCS in Scotland will require a suitable transport network for CO_2. This study examined options for transporting CO_2 between the sources and storage sites identified. Various onshore and offshore routes and technologies were examined. The latest UK and international codes and standards applicable to CO_2 pipelines were used.

Table 11
Source categories defined as Tiers with examples.

Tier	Source category	Source size (Tonnes CO_2/year)	Examples
0	Large	> 1 million	Coal fired power station, hydrocarbon refinery, major chemical works
1	Medium	50,000 to 1 million	Chemicals, glass, food manufacturers, large Combined Heat & Power (CHP) & Combined Cycle Gas Turbines (CCGT's)
2	Small	1,000 to 50,000	CHP units, incinerators, small to medium industrial works

Sources were categorised according to their **output per year** (Table 11). The tiers provide some indication of the potential for applying a CCS solution at each level and are linked to emission allowances allocated under the European Union Emissions Trading Scheme. Large (Tier 0) sources are recognised as the primary focus for any CCS scheme as the cost of allowances under European Union Emissions Trading Scheme should make it more economical to store the carbon than to pay for or trade any excess over the emission allowance. The CO_2 transportation network will be built around these centres. Medium (Tier 1) sources may be less economically suited to a CCS solution. Their location is likely to determine whether they are included in the network. For instance, offshore installations (Medium (Tier 1) sources that produce in total 23.7 Mt/year of CO_2) are not included in the example network discussed below. It is unlikely to prove either practical or economic to include most small (Tier 2) sources in a CCS scheme.

All **large Scottish sources** are located along the Firth of Forth except the gas-fired power station at Peterhead. Several medium sized (Tier 1) clusters could feasibly be associated with the large sources. For example, St Fergus Gas Terminal naturally links to the large Peterhead source and plants at Stirling and Mossmorran to the large Longannet power station (Figure 4). Future projects, such as replacement of power generation at the Hunterston Nuclear site, were not added to CO_2 volumes but network access was modelled, and replacement of existing plant was included.

6.1 Network design

A well-developed **oil and gas pipeline transport infrastructure** is present throughout the onshore UK and the offshore UK Continental Shelf. Parts of this infrastructure may become available for re-use and potentially could be used to transport CO_2. For example, a previous proposal demonstrated that the pipeline from the vicinity of Peterhead to the Miller field is technically capable of carrying a substantial volume of CO_2. It could well form a key element in any future offshore CO_2 pipeline network and the potential for its use in this context should be examined in detail as a priority. However, re-use of onshore and offshore pipelines raises major issues related to change of use in areas of planning, capacity and safety, in addition to various technical questions. Assessing the possibility of re-using each pipeline for CO_2 transport would require a line by line analysis and is beyond the scope of this study. However, in broad terms, and dependant upon pipelines becoming available, offshore pipelines are more likely to be suitable for re-use, whereas onshore, the potential for re-use will be more restricted. Importantly, sections of the onshore National Transmission System (NTS) could be used as part of a start up or phased approach while gas flow is low. Thus, taken together, use of existing onshore and offshore pipelines may be viable for the small volumes (~3Mt/year) of CO_2 required for a demonstration project.

The design of a network for Scotland's CCS system therefore reflects the location of the key large (Tier 0) emitters, all but one clustered around the Firth of Forth, and the various CO_2 storage options in the Scottish defined offshore area. These groupings and the distances between them naturally suggest an approach consisting of **source hubs** connected by a transport spine to **storage hubs**. The presence of a hub near several storage sites allows a variety of storage technologies (saline aquifer, depleted hydrocarbon field or CO_2-EOR) to be pursued as opportunities permit, thereby lowering risk. Four storage hub locations were chosen to permit examination of relative transport costs between various areas and the effect of various assumptions about the re-use of existing infrastructure. The storage hubs are named after local oil fields (Captain, Dunbar, Brae and Gannet; Figure 16) and are not necessarily optimal.

6.2 Transport options

The viability of transport by pipeline and ship were both assessed. Pipeline design is a complex issue with many factors affecting the building of this infrastructure. A CO_2 pipeline system must be able to accommodate the full range of conditions from fast ramp up rates and shut-downs of power stations and the closure of geological storage sites. It must accommodate varying flows, surges and variations in composition of the CO_2 fluid itself. Key issues unique to CCS are:

- chemical and physical properties of the CO_2 including any impurities within the CO_2 stream;
- consideration of pressures, to maintain the CO_2 in the required phase throughout the network without exceeding safe levels at other points;
- legislation specific to CO_2 including UK Health and Safety requirements and international codes of practice.

A **pipeline operating pressure** above 100 bar is desirable with a minimum pressure of 90 bar in order to prevent phase change within the pipe. This maintains the CO_2 well above its critical point pressure of 73.9 bar. This pressure margin also allows for a degree of contamination of the CO_2 stream.

Although elements within the National Transmission System onshore pipeline system may be available and suitable for use within a CO_2 pipeline network, this possibility was not considered within the economic assessment discussed below.

In terms of the technical and economic viability of **transporting CO_2 by ship**, this study focussed on transport of captured CO_2 from a location in the Firth of Forth to the Peterhead area (Figure 16). The assessment was limited to vessel access, berthing and ship support services only. No account was taken of any specialist storage tanks, pressure and cooling systems necessary for loading and discharge of the CO_2. Note that, to minimise disruption to the capture process, storage tanks should be sufficient to allow 50% redundancy over and above the ship's cargo capacity.

The model for costs of transport by ship assumes newly designed vessels of 18,000 m^3 capacity, total cargo pumping rate of 1,500 m^3/hr, no waiting on tides, and that discharge occurs in Peterhead Harbour (although discharge at an offshore location would considerably reduce overall harbour costs). A fleet of four vessels would allow in excess of 13.5 Mt of CO_2 to be transported per year. Transportation cost would be in region of £4.57 per tonne. The capital cost for the vessels, whether new build or converted, has not been included in the cost model. In the final analysis, five possible transport options, each with the same offshore storage hubs, were identified and costed. Options for transporting CO_2 from the Tees/Tyne area were also assessed (Table 12).

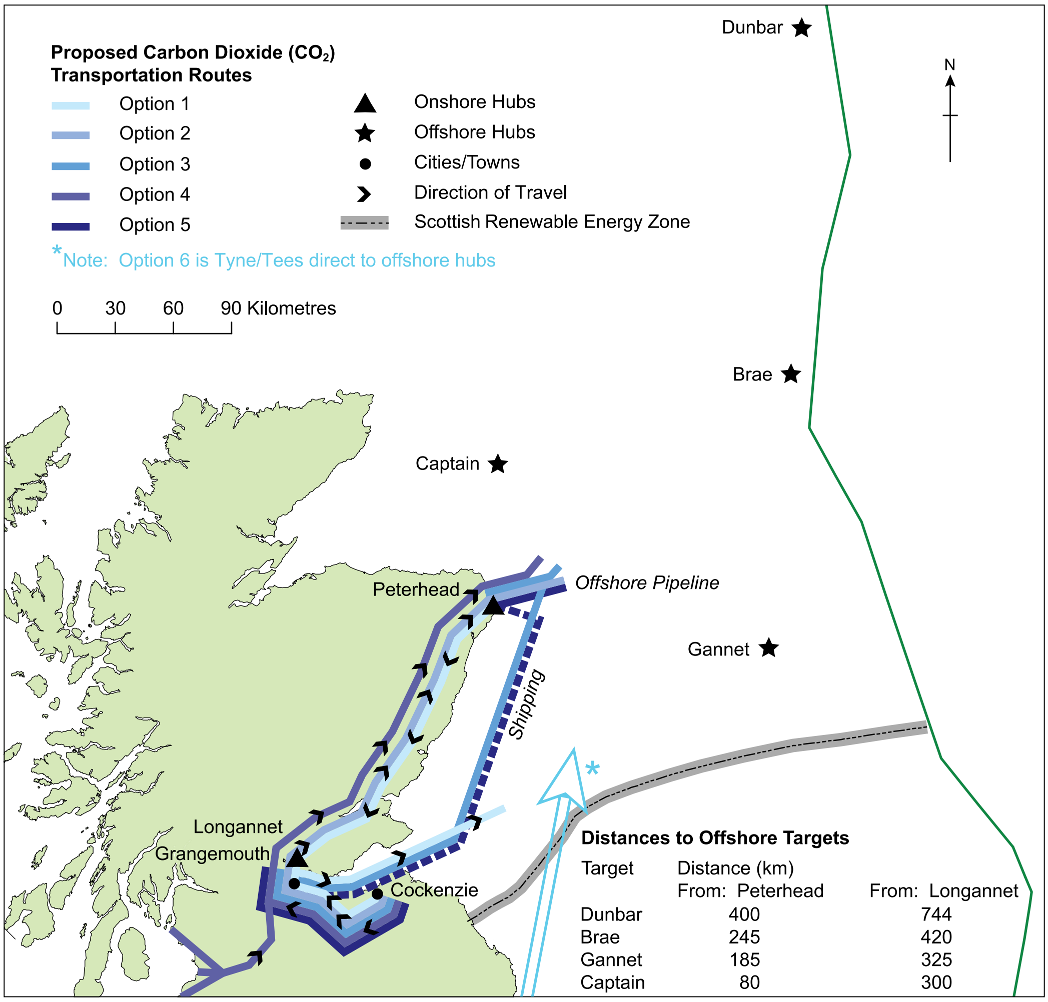
Table 12
Summary of possible transport options identified through consideration of the locations of CO_2 sources and potential storage sites.

Network Option
1–Peterhead to Forth (Longannet) onshore pipeline
2–Forth to Peterhead onshore pipeline
3–Forth (Longannet) with offshore pipeline route to Peterhead
4–Full network
5–Shipping from Forth to Peterhead hub
6–Tyne/Tees direct to offshore storage hubs

Assessment of transport options

- Assessment of the five pipeline and shipping options for transportation of CO_2 shows that they are within the scope of costs for a major infrastructure project.
- The option using ship transport, a 'floating pipeline', is feasible and may be comparable to pipeline options in terms of capital cost, but with up to four times higher operating expense.
- A more detailed examination would be required to accurately differentiate between the onshore and offshore routes from the Forth to Peterhead (options 2 and 3).
- This appraisal does not consider a phasing of the construction of the network but assumes a relatively quick build-up to full capacity due to the small number of large sources.

Figure 16
Summary of proposed CO_2 transportation routes.



The implications of **importing CO_2 from areas outside Scotland** were investigated by examining the route from the Tees–Tyne area to storage sites offshore Scotland (Option 6). Linking directly into a pre-existing network within Scotland would be costly in terms of both capital and operating costs, not least because pipelines are complex systems. This study suggests that multiple feeder pipelines from the onshore clusters to the offshore storage sites is likely to offer a more cost-effective solution with CAPEX ranging from £1.4 to £2.3 billion and OPEX ranging between £27.5 to £53.5 million depending on storage hub destination. Whilst this introduces complexity into storage management, it allows for much more flexibility in phasing construction and operations.

Figures 17 & 18 show the **costs of the various options**. Option 2 (onshore pipeline) forms the lowest cost option in terms of capital expense (CAPEX) for all offshore hubs and the lowest cost option in terms of operating expense (OPEX) for all except the Gannet hub where Option 3 (offshore pipeline) is slightly less. Captain is the lowest cost target for Option 2. The overall costs of Options 2 and 3 are comparable. Option 3 is slightly more expensive, but constitutes a viable alternative to an extensive onshore pipeline. Option 1 (principal pipeline from the Forth to the offshore hubs) and Option 4 (full network) are more costly than either Option 2 or Option 3. The capital costs of shipping Option 5, are comparable with those of the other options, but the high operating costs and risks suggest that it is unlikely to prove a viable long term solution.

Figure 17
Capital expenditure for the five CCS network options investigated for each offshore hub (in £ Billion).

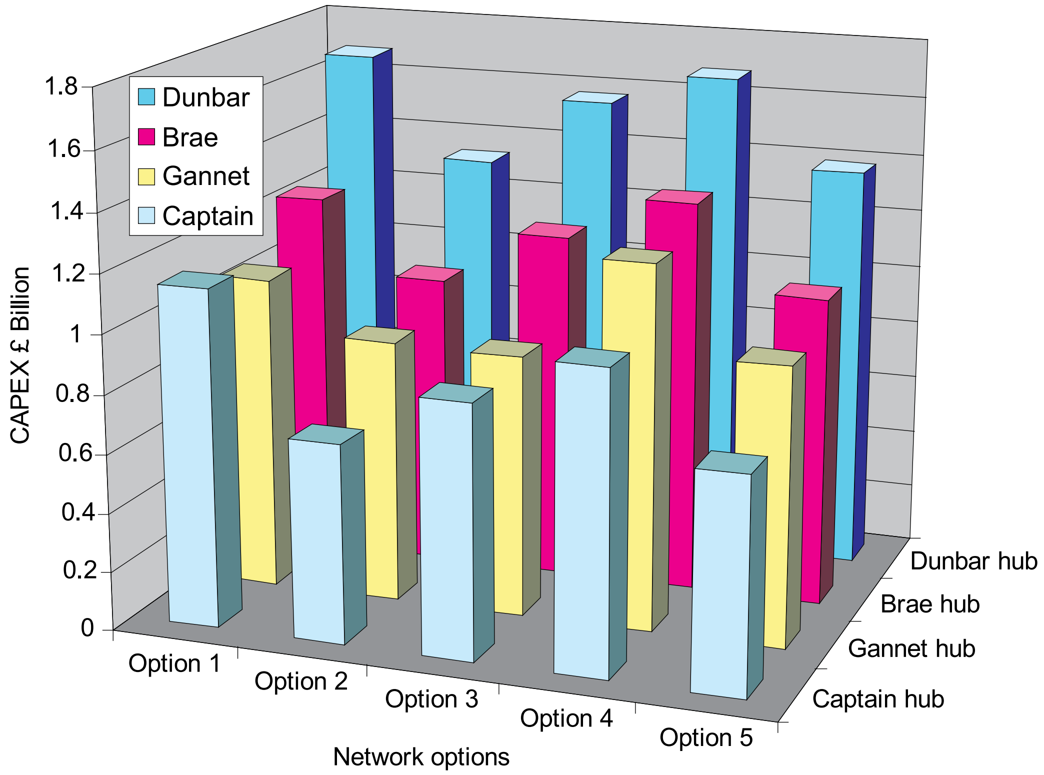
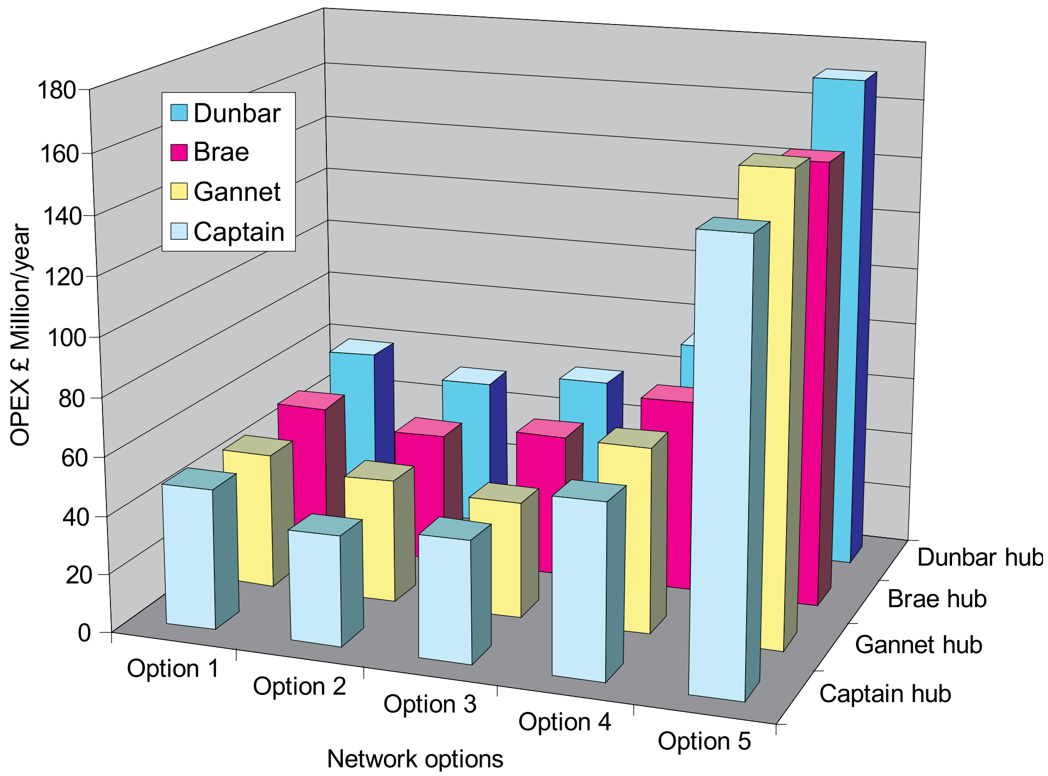


Figure 18
Operational expenditure for the five CCS network options investigated for each offshore hub (in £ Million per year).



CO_2 transport options between sources and storage sites—key conclusions

- Five network options, linking CO_2 source and storage hubs have been identified and a technical and economic assessment undertaken.
- A sixth option, importing CO_2 from NE England was also investigated. Here, multiple feeder pipelines to offshore hubs are likely to form a more appropriate means of accepting additional CO_2 from NE England rather than attempting the technically complex option of connecting directly into a pipeline network within Scotland.
- Some re-use of facilities is possible, especially in the early stages of CCS projects.
- The potential for using the Peterhead to Miller pipeline and the National Transmission System infrastructure as a key element of a Scottish CO_2 pipeline network should be examined in detail.
- A pipeline network used to transport 20 million tonnes/year of CO_2 from sources to the storage hub at CAPEX costs of £0.7 to £1.67 billion and OPEX costs of £38 to £74 million depending on hub location and excluding the shipping option. OPEX for shipping ranges from £148 to £171 million depending on hub location.

7| Economic modelling of potential CCS schemes in Scotland

Economic modelling of possible CCS projects in Scotland was carried out to compare costs with conventional non-CCS power stations. The CCS schemes were compared to each other and the 'without CCS' alternatives to estimate the level of subsidy that would be required to make CCS projects economic.

Five sample schemes were selected for study as shown in Table 13. They are based on key CO_2 sources from the power stations at Longannet and Peterhead combined with network and storage options selected from the options presented earlier in this study.

Table 13
CCS schemes selected for economic analysis.

No.	Driver Source	Non-CCS Technology	CCS Technology	Storage Hub	Primary transport required
1	Longannet	2.4 GW supercritical coal	2.4 GW supercritical coal with post combustion capture	Brae	Forth hub (vicinity of Longannet) to Brae with alternatives of new and existing (Miller) pipeline
2	Longannet	2.4 GW supercritical coal	2.4 GW supercritical coal with post combustion capture	Gannet	Forth hub to Gannet with new pipeline
3	Peterhead	1.2 GW CCGT*	1.2 GW CCGT with post combustion capture	Brae	N.E Scotland hub (vicinity of Peterhead and St Fergus) to Brae via existing Miller pipeline
4	Longannet	2.4 GW supercritical coal	2.4 GW supercritical coal with post combustion capture	Gannet	Import of CO_2 from N.E. England hub (vicinity of Blythe/ Lynemouth) connected into Scottish Network using new pipelines
5	Peterhead	1.2 GW CCGT*	1.2 GW CCGT with post combustion capture	Captain	N.E Scotland hub to Captain using new pipeline

CCGT, Combined Cycle Gas Turbine*
GW, Gigawatt

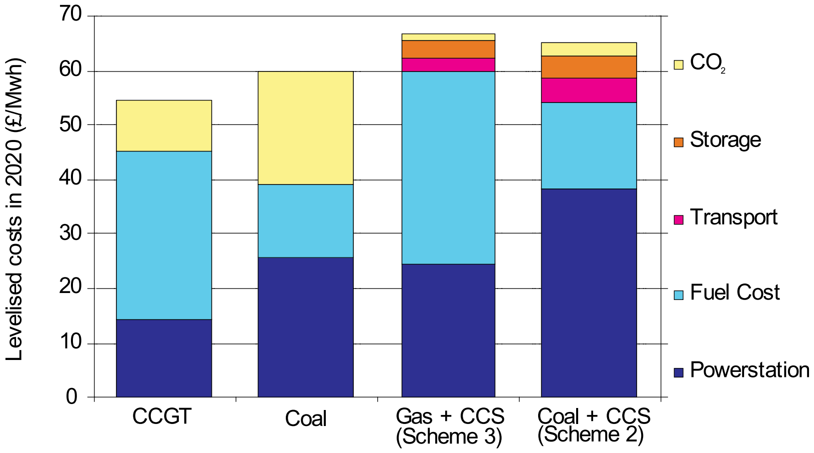
Table 14 shows these schemes ranked by **cost of abatement** (in £/t CO_2). Each project was compared with its non-CCS alternative, shown in Table 13, to calculate the subsidy (in terms of £/t CO_2 captured) required to give returns similar to those of the non-CCS alternative. On a lifetime annual basis 'required' subsidies range between £93 M per year for Scheme 5 to £132 M for Scheme 4. The required subsidy (in £/t CO_2) is roughly equal to the abatement cost minus the assumed market price of CO_2 in 2020.

Table 14
Source to storage schemes ranked by cost of abatement (in £/t CO_2).

Scheme no.	Scheme	Abatement cost (£/t CO_2)	Required subsidy (£M/year)	Required subsidy (£/t CO_2 captured)	Electricity cost (£/M Wh)
2	Longannet supercritical coal to Gannet hub	37	98	7	65
1	Longannet supercritical coal to Brae hub	39	117	9	66
4	Longannet supercritical coal to Gannet hub with imported CO_2	40	132	10	67
5	Peterhead CCGT to Captain hub without full network	64	93	30	65
3	Peterhead CCGT to Brae hub	70	111	36	67

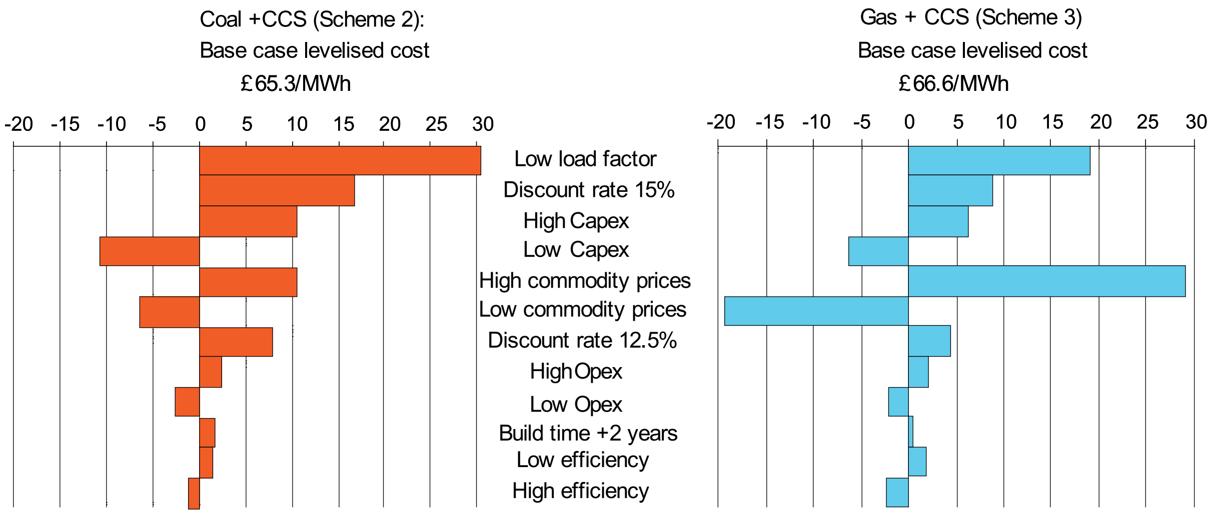
The **cost over the lifetime** of the energy generating system (levelised cost) of Scheme 3 and Scheme 2 was compared to that of conventional coal- and gas-fired generation (Figure 19). Calculations of the required subsidy assumes a rate of return of between 9% to 11%. This shows that despite the difference in abatement cost, gas-and coal-fired CCS schemes have very similar levelised costs (Figure 19 and Table 13). However, although the amount of financial support for gas-fired CCS projects is similar to that required to support coal-fired CCS, the tonnage of CO_2 abated is much higher in a coal scheme.

Figure 19
Breakdown of levelised costs in 2020.



Sensitivities on the assumptions—The high degree of uncertainty in elements of cost and the performance of CCS plant in the economic modelling exercise flows through to the estimates of the cost of electricity generation of CCS Coal and CCS Gas schemes in quite a different way (Figure 20). For example, factors which have a strong impact on the power station element of the levelised costs of the schemes such as a reduced load factor (50% instead of 85%), higher discount rates and a higher CAPEX will have a disproportionate effect on the economics of CCS Coal because of the greater weight of the power station costs in CCS Coal. Conversely, assumptions that have a strong impact on fuel costs such as sensitivities to commodity prices will have a stronger effect on the economics of CCS Gas.

Figure 20
Comparison of the impact of sensitivities on power generation by CCS Coal and CCS Gas.



Impact of CO_2-EOR on results— CO_2-EOR may have the ability to lower the overall subsidy required and provide an additional incentive for development of CCS. It may add value to Scotland's hydrocarbon reserves by prolonging the life of oil fields, delaying their closure and postpone decommissioning costs.

Modelling of CCS Schemes—key conclusions

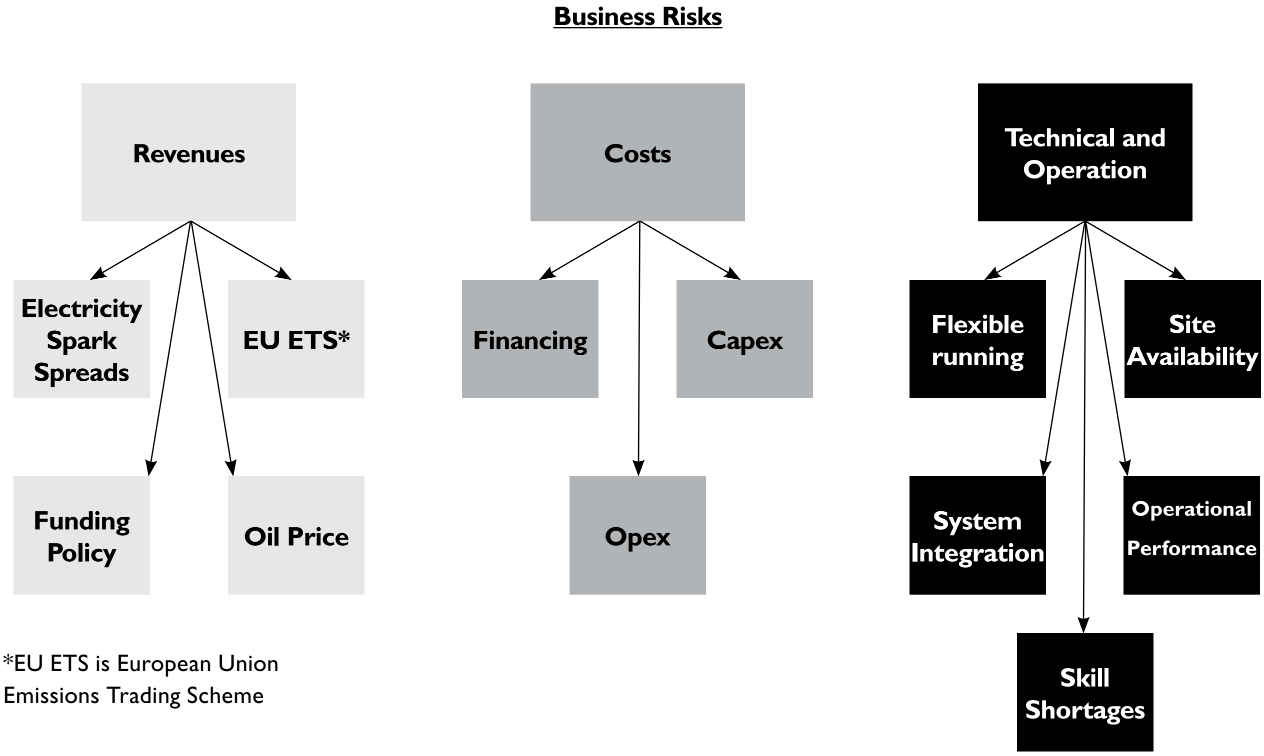
- The underlying economics of energy projects drive power industry development.
- The levelised costs (in £/MWh) of CCS Gas and CCS Coal are similar.
- CCS schemes are likely to be significantly more expensive than standard conventional Combined Cycle Gas Turbine and pulverised coal plant.
- Uncertainty in the costs and performances of CCS schemes can considerably affect assessment of the relative merits of coal- and gas-fired schemes.
- High or low future commodity prices will determine whether costs for CCS will be competitive with non CCS power generation.
- Although the costs of CCS schemes are similar, CCS coal-fired power generation abates more CO_2 than CCS gas.

8| Business risks faced by early CCS projects

The principal financial risks associated with anticipated revenue, costs and technical/operational aspects of CCS projects were identified to inform the discussion of business models for early CCS projects.

Early CCS projects are likely to consist of dedicated transport and storage facilities matched with each source. This study concentrated on the risks associated with projects of this nature. A more mature CCS industry may well consist of multiple projects with a shared infrastructure—many capture projects feeding into a CO_2 pipeline network which is then linked to a multitude of storage sites. The configuration of these early projects means they are likely to face additional business risks. Three key areas of business risk and their mitigation were investigated: Revenue stream risks, Cost risks and Technical and Operational risk (Figure 21).

Figure 21
The key areas of business risk.



*EU ETS is European Union Emissions Trading Scheme

Revenue streams—the power station will be the principal source of income to any CCS project selling 'low-carbon' electricity to the market. Uncertainty over gas, coal and carbon prices in the long term brings with it uncertainty regarding the gross margin for power generators. Furthermore, the UK electricity generation mix is likely to evolve in the years to 2020 both as a result of policy and in response to commodity prices; more nuclear and renewables capacity could result in lower usage levels of CCS plants and therefore lower overall revenues.

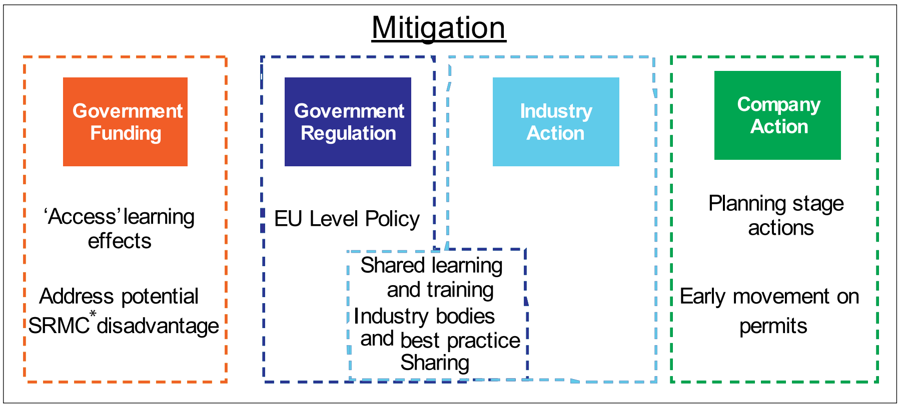
Costs—Capital costs (CAPEX) form the single largest source of cost uncertainty and are likely to dominate the character of overall schemes. The technologies of pipeline systems and storage sites are better known than those of other elements, so their capital costs are more certain. However, these form a large proportion of the total capital requirement so any overrun will have a disproportionate impact on overall project returns. Uncertainty in the thermal efficiency of CCS plants will give rise to significant elements of risk in the operational cost (OPEX), through fuel costs. The relative novelty of CCS technology and the risks associated with it suggest that the costs of financing early projects will be higher than those of more mature technologies.

Technical and Operational risks—There will be significant cost savings from learning effects. Technical and operational efficiency will also improve with experience. The two areas most likely to achieve significant improvement are the power plant (which currently accounts for approximately two thirds of lifetime costs in each CCS scheme) and storage sites. Pipelines are much more of a known quantity, and levels of operational risk can be well estimated in advance. Some additional financial risk may be associated with the construction of early CCS power plants, where delays are more likely than for conventional stations because of the complexity of the projects.

9| Business models

With costs and risks identified, business models have been constructed and compared in order to identify the best contractual structure for enabling CCS projects. Business models need to address the manner in which market, technical and operational risks are distributed between the various parties involved (Figure 22). The challenge is to find a business model which shares risks and rewards in such a way that acceptable returns are earned by each individual party as well as for the project as a whole.

Figure 22
Mitigation of risks in a CCS scheme.

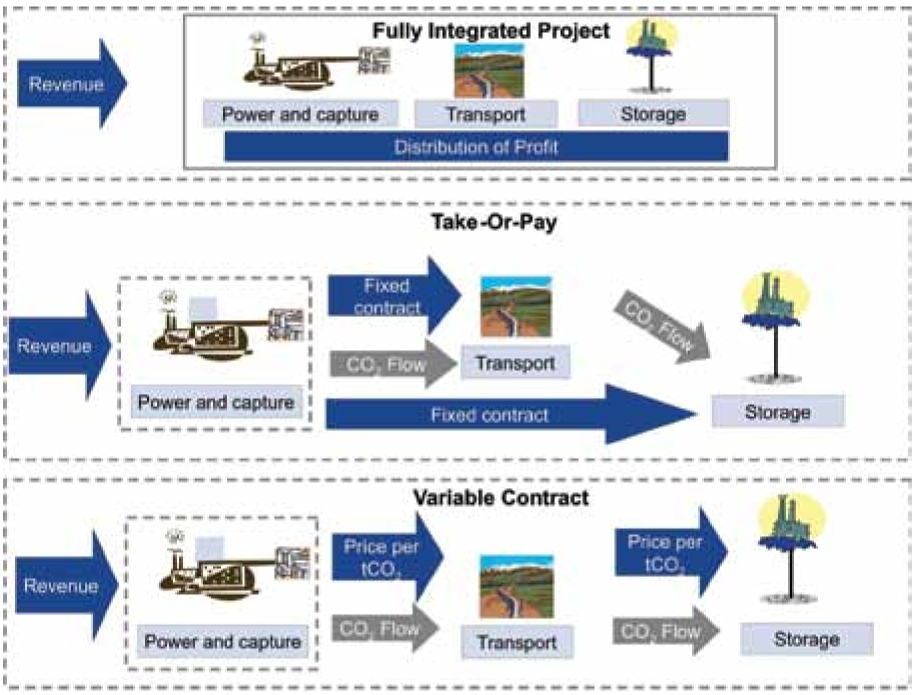


* Short run marginal cost

In addition to appropriate action at company level, the CCS industry as a whole should work to reduce these risks, for example through technology testing and information sharing. Finally, the government has an important role to play in mitigating risks, both by introducing a policy framework favourable to CCS and in establishing the appropriate funding mechanism for CCS to allow the industry to overcome the effects of high marginal costs in the short term.

Different business models share risk and reward between the participants in different ways. Figure 23 shows the three principal business models examined.

Figure 23
Summary of the three business models examined in this study.



'Fully Integrated Project'—a single company in which all partners invest and receive an equal return on their investment. In this model, all parties are exposed to all the risks over the whole chain but the exposure of the parties to individual operational risks is reduced. In the other models the partners do not form a single company but are governed by contractual agreements.

'Take or Pay contract'—comprises a set of contracts each specifying a fixed payment to each partner. Each partner bears full responsibility for its own operational risk with only limited risk passed on to other parties.

'Full Variable Contract'—consists of contracts between power plant, pipeline and storage site operators specifying a price per unit of CO_2. In this model, operational risk can, to some degree, be passed on to parties down the chain.

Of the business models analysed, a **'Fully Integrated' model appears to be the most attractive in terms of risk sharing**. However, companies that are accustomed to operating in different sectors expect different returns and this may prevent this model from working satisfactorily. Typically, utilities expect their projects to return a pre-tax real rate of return around 10%, a regulated pipeline network expects a rate closer to 6%, whereas hydrocarbons Exploration & Production companies expect returns in excess of 15%. This model may not function well if applied to a CO_2 system with several sources and storage sites linked by a common network.

Under the **'Take-or-Pay' business model**, while the pipeline and storage operators are fully exposed to their own risks, they are insulated from operational problems further up the chain. This model provides the greatest incentive for parties to manage their own operational risks but exposes the power station entity to significant revenue uncertainty.

Under the business model with **variable contracts**, the pipeline and storage operators are exposed to the operational risks of the power station, but cannot in turn pass on their own risks in the same way as the power station. While a mixture of Take-or-Pay and Variable contracts can be used to share operational risks it is less appropriate to use contracts to share risks such as those associated with capital overrun.

Identifying why a **commercial organisation** may or may not want to undertake CCS projects is a complex question. The question can be addressed at three levels; corporate strategic reasons, tactical business reasons or business implementation reasons. The viewpoint of any organisation also depends on its position in the future CCS value chain as power/CO_2 source, capture provider, transport operator, or storage provider.

10| Funding mechanisms

Potential funding mechanisms were examined on their ability to address key business risks and meet specific policy aims in order to identify the most appropriate funding method. Each funding mechanism was identified and flagged according to its ability to meet the criteria in Table 15 below.

Mechanism	Funding magnitude	Ability to offset increased capital costs	Ability to offset increased short run costs	Ability to encourage CCS pilot projects in Scotland	Ability to encourage 'long term' Scottish CCS
No Additional Funding	Zero	Zero	Zero	Zero	Low –will not encourage CCS until CO_2 price rises to appropriate levels
Direct funding of R&D pilot Projects	Low	High –but only in small scale projects	High –but only in small scale projects	High –but only in small scale projects	Low –encourage demonstration but extra funding needed to scale up projects
Direct funding of a percentage of project costs	Medium –mechanism requires that financial support be provided upfront	High –government will provide funding (risk allocation based on funding details)	Zero –creates danger of a low load factor	High	Medium
Fixed income subsidy	Medium	Medium –developer likely to bear CAPEX risk but funding could be sized to compensate for capital cost	High	Low –lack of construction stage support will discourage demo projects with uncertain capital costs	High
Market based subsidy	Medium	Medium –developer likely to bear CAPEX risk but funding could be sized to compensate for capital cost	High	Low –lack of construction stage support will discourage demo projects with uncertain capital costs	High
Direct funding of transport and storage 'network'	Medium/High –costs would largely be set by overall size (dictated by scale of chosen network)	Medium –may help with storage liability issues	Medium	Low –lack of construction stage support will discourage demo projects with uncertain capital costs	Medium

Table 15

Comparison of funding mechanisms and merits of CCS in Scotland.

Green — Positive criteria indicator

Orange — Neutral/Average/uncertain criteria indicator

Red — Negative criteria indicator

Black — Very Negative criteria indicator — Potential 'show-stopper' that could make mechanism untenable.

	Ability to link with other mechanisms	Ease of application in Scotland	Likely 'value for money' maximise no. of CCS projects	Likely 'value for money' — minimise CO_2 abatement cost	Potential to develop Scottish CCS expertise
	High –will always be available whichever other funding streams are chosen	Good	High – will impose no extra costs	High –will impose no extra cost	Zero
	High	Good	Low –unlikely that public will see direct benefit of lower energy costs	Low –unlikely that public will see direct benefit of lower CO_2 emissions	High
	Medium –favourable to link with scheme to address increased running costs	Difficult –no state aid issue but Scottish Government budget implications	Medium –potential for overfunding	Medium –potential for overfunding	High
	Medium –could link with a mechanism that funded capital aspects	Medium	Medium –should provide a good incentive but overfunding possible if subsidy at wrong level	Medium –should provide a good incentive but overfunding possible if subsidy at wrong level	Medium –if non-Scottish companies selected potential for developing Scottish expertise reduced
	Medium –could be part of raft of schemes (projects could only access one funding stream)	Very Difficult –would be very complicated to impose	High –should provide set level of CCS projects at lowest cost	High –should provide set level of CO_2 abatement at lowest cost	Medium –if non-Scottish companies selected potential for developing Scottish expertise reduced
	High	Difficult –politically difficult to fund and take risks using public resources	Medium –potential for overfunding if pipelines remain unused	Medium –potential for overfunding if pipelines remain unused	Medium –pipeline and storage expertise encouraged but capture expertise development uncertain

In practice each option has both advantages and disadvantages and there are no clear preferences.

Of the 'high-level' mechanisms examined, a phased approach to funding of CCS in Scotland appears to have merit:

Phase1, short term Direct funding of CCS Research and Development and pilot projects will enable cost discovery and allow access to initial learning effects. It will lower uncertainty regarding capital costs and directly stimulate Scottish CCS expertise. One possible route is to co-finance the capital of R&D and smaller scale demonstration projects with public/private funding partnerships (highlighted in Table 15).

Phase 2, medium term The aim of the favoured medium term funding mechanism is to offset the potential short-run cost disadvantages of CCS. On balance, the preferred solution for the medium term support of CCS is fixed income support (highlighted in Table 15). Depending on the aim of the funding mechanism, the most appropriate form of subsidy will differ:

- A subsidy per MWh of CCS electricity generated will encourage CCS generation but may not minimise the cost of carbon abatement.
- A subsidy per tonne of CO_2 abated (versus a benchmark on a project to project basis) would minimise the overall cost of reducing CO_2 emissions, but may not be technology neutral (as it favours projects that will 'offset' coal generation) and may not minimise the overall cost of electricity generated from CCS.

If the subsidies are required to bring the returns on CCS projects to a level comparable with their non-CCS equivalents, each of the schemes listed in Table 13 would require support in the region of £100M/year. European funds are available to support such projects, but access to these sources is limited and open to competition from all European countries.

11| Comparison with other carbon abatement options

To put the analysis of CCS economics in context, the costs were compared with those of carbon abatement using other low-carbon power generation technologies. These included onshore wind, offshore wind, biomass, wave, tidal, Combined Heat and Power (CHP) and nuclear power generation.

Carbon abatement cost (£/t CO_2) is calculated as the additional cost of generating a given amount of energy using each technology in place of a conventional plant divided by the carbon savings that would be achieved. Lower abatement cost is better because it means that a greater amount of CO_2 is abated for each £ spent and thus greater revenue in terms of carbon credits. In market terms, it indicates the price of CO_2 needed to cause an informed investor to switch from building a conventional generation plant to one based on the alternative technology.

The **alternative technologies** were examined under certain assumptions regarding costs and commodity prices, and taking a simple view of comparable discount rates (taken at 10% across all technologies). Energy efficiency, large-scale industrial Combined Heat and Power (CHP) plants and new build nuclear power generation appear as the most cost-effective options for carbon abatement. However, CHP is challenging to install and nuclear has a very long lead in time and significant issues concerning waste disposal and decommissioning. The abatement costs of CCS Gas and CCS Coal appear to be slightly greater than that of onshore wind, rather less than offshore wind and significantly less than tidal stream or wave power generation.

Realistically, it must be recognised that carbon abatement in Scotland in 2020 will not simply reflect relative costs. Other factors limit the deployment of these technologies. For example, growth of CHP will be limited by the availability of an appropriate heat load, and the present position of the Scottish Government on nuclear power suggests that no new nuclear capacity will be added. Also, most of the potential for onshore wind capacity renewable generation is likely to have been achieved by 2020, with the best and cheapest sites, supported by schemes such as the Renewable Obligation Scotland, fully occupied. It is unlikely that the challenge of reducing carbon emissions in 2020 will be fully met by the alternative technologies examined. In addition, several studies have shown that the variability of wind power will require either very large EU-sized interconnectors or 80% backup generators from fossil fuels. Scotland has to examine and deliver CCS to achieve its present low-carbon aims.

Concluding remarks

Evidence for climate change and its potentially catastrophic effects on the world is becoming clearer year on year. Hydrocarbon output from the North Sea is in decline and world oil and gas markets have proved highly volatile over the last couple of years. Carbon Capture and Storage offers Scotland greener energy and can help improve security of energy supplies through delivering increased choice in energy sources.

This study has examined current and future CO_2 output in Scotland and north-east England and it is clear that a significant percentage of industrial emissions could be captured and stored in geological structures. The study has identified significant potential CO_2 storage resources offshore but notes that at this stage there is a need for further study to determine the amount of storage that will be available in practice. Technically feasible ways to transport CO_2 from key onshore CO_2 emission sites to offshore storage sites have been identified.

The study has shown that the financial costs for initiating CCS will be high but are comparable with the current costs of commercial renewable energy sources. In a similar way to the renewable energy industry financial support is also crucial for CCS to commence in Scotland. Recent history has shown that carbon prices are volatile and subject to market forces which recently have seen the value of the EU permit to emit one tonne of CO_2 drop to around € 10 (~£8). Carbon prices need to be stable and high over the long term in order for large-scale CCS to be self financing. Timely initiation of CCS will bring advantage to the Scottish economy by establishing this country as a leader in CCS technology and skills —as well as making a major contribution to delivering Scotland's and the UK's climate change targets.

Scotland has the geology and the motivated and innovative skills base required to deliver a major CO_2 storage industry that will benefit both the Scottish economy and the world's environment. The keys to CCS becoming a reality in Scotland are political will, public acceptance, and the creation of a supportive regulatory and commercial environment that leads to investment by industry. This study makes a significant contribution to providing government, industry and citizens with a firm basis for future decisions.

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