CARBON DIOXIDE CAPTURE AND STORAGE: A WIN-WIN OPTION? (The Economic Case)

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by

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Executive Summary

Introduction

Capture and storage of carbon dioxide produced in the combustion of fossil fuels offers one option for attaining large-scale reductions in the emissions of anthroprogenic greenhouse gases. This involves three basic stages; capture, transportation and injection into a storage medium. Carbon dioxide capture would be most efficiently applied to large "point sources" in order to gain economies of scale both in the capture process itself and in subsequent transportation and storage. Examples of such sources include fossil-fuelled power stations, oil refineries, petrochemical plant, cement works and iron & steel plant.

The UK currently derives 90% of its primary energy and generates over 70% of its electricity from fossil fuels. Moreover, it has access to substantial carbon dioxide storage capacity. In particular there is potential for storage combined with Enhance Oil Recovery (EOR) in the oil fields of the central and northern North Sea areas, while the gas fields of the southern North Sea offer a large near shore resource for storage. In the longer term saline aquifers offer an even large storage capacity. Consequently carbon dioxide capture and storage needs to be assessed as an important potential option for greenhouse gas abatement for the UK

This report describes the results of a scoping assessment for DTI, which has concentrated on carbon dioxide capture from fossil fuel power stations. The overall objective of the study was to develop a basic understanding of the economic case for capture combined with storage through EOR or injection into depleted natural gas reservoirs in the North Sea.

Key Findings and Recommendations

- There is a range of EOR and injection options depending on whether carbon dioxide is captured from existing power plant or new purpose built facilities, and the location of these plant relative to the oil and gas fields.
- There is considerable uncertainty in the assessment of the costs of carbon dioxide storage through EOR or injection into depleted natural gas reservoirs. This arises from the wide range placed on cost estimates for carbon dioxide capture plant, to reflect site specific variations, and uncertainty regarding the yield and market value of the additional oil produced by EOR.
- With the central cost and performance data used in the assessment some financial support will be needed to encourage both EOR and storage. This conclusion is inline with other assessments for the North Sea (Kinder Morgan, 2002) and North American experience (DTI, 2003).
- It was estimated that carbon dioxide storage in depleted gas reservoirs would require financial support of the order of £20-27/tonne CO_2 [1]stored equivalent to £125-341/t carbon abated[2].

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[1] Most costs reported in this Executive Summary were estimated relative to the generation costs and carbon dioxide emissions of a new GTCC plant. See later in the Executive Summary for a fuller explanation.
[2] The net abatement of carbon dioxide emissions is equal to the amount of gas that would have been produced in generating the same quantity of electricity with non-capture plant. This is not equal to the amount captured and put into storage. See main report for further explanation.

- Carbon dioxide storage through EOR is more cost effective requiring financial support of the order of £4 to £10/t CO_2 stored, or £48-183/t carbon abated. EOR is the lower cost option because it gains some financial benefit from the additional oil produced, which offsets some of the capture and transportation costs.
- Based on the above costs an EOR scheme involving 8Mt of carbon dioxide per year would require financial support of between £32M and £80M per year over 20 years.
- The above values are based on central cost and performance estimates. The financial support would be significantly reduced if EOR was applied to those field particularly suited to carbon dioxide based enhanced recovery or if the oil price increased from the $20/bbl assumed herein.
- The assessment was base on "present day" costs and performance data for separation plant. There are opportunities for technical innovation and "learning by doing" that could reduce capture costs and improve performance thereby reducing the required level of financial support.
- The assessment was not intended to assess alternative capture technologies, and indeed has not covered all potential options. However, it is noteworthy that new build IGCC plant was the most cost effective of the coal-fired options included in the study.
- The economic assessment has concentrated solely on carbon dioxide abatement, but EOR offers added benefits, including increased oil recovery, and hence improved security of oil supplies to the UK, and further investment in the North Sea helping retain and create jobs in the UK's offshore industry.. Moreover, taking a lead with the development of carbon dioxide capture and EOR technology could give UK industry a strong competitive edge in future international markets.
- Carbon dioxide EOR and storage in depleted gas reservoirs faces other barriers to implementation. These include the distribution of financial risks between stakeholders and uncertainty over long term financial support from policy instruments such as carbon permit trading.
- It is recommended that action be taken to reduce the uncertainty over the level of financial support needed for EOR, which has been highlighted by this study. This requires project specific assessments of particular carbon dioxide capture options applied to existing power plant or particular locations for new build facilities. These should be linked to similar engineering assessments of cost and yield of oil from the implementation of EOR on specific oil fields.
- It is recommended that the working group consider the strategic priority in pursuing EOR based carbon capture and storage. For example should this be to demonstrate the complete system, leaving the choice of capture technology to financial considerations alone. Alternatively should EOR be used as a comparatively low cost mechanism for supporting the demonstration of new and innovative cleaner coal technology integrating carbon capture.

Options Examined

The options for carbon dioxide capture considered were retrofitting equipment to existing coal and natural gas fire plant as well as the construction of new coal (IGCC) and gas (GTCC) technology.

A range of options for gas storage have been proposed for the UK including injection into depleted oil and/or gas reservoirs, geological aquifers, deep unminable coal seams and on or below the deep ocean bed. The two options for storage considered in the study are utilisation for Enhanced Oil Recovery (EOR) and injection into depleted natural gas fields. EOR has the attraction of offering an economic return from additional oil production that will at least partially offset the cost of capture and storage. The two options have different timescales. Gas injection utilises near shore fields and requires comparatively little offshore infrastructure, and can be undertaken as and when it is needed within an integrated national greenhouse gas abatement strategy. In contrast EOR needs to be initiated before oil fields reach close of production, which for some of the early fields is before 2010. Therefore decisions have to be made on a shorter timescale with EOR, otherwise the capacity for storage will gradually decline as fields are closed.

It should be noted that the option of returning to abandoned oil fields at some later date to use them purely for storage does remain available. However, many UK oil fields are further offshore than the gas fields and therefore would be less attractive both technically and economically as a pure disposal option and would be used later. Returning to abandoned oil fields to implement EOR is unlikely to be economic since the production and transport infrastructure for oil would have been decommissioned.

Options for transporting the large quantities of carbon dioxide involved in full scale capture and storage (i.e. 1-30Mt/yr) are likely to be limited to pipeline systems although ship transport of liquefied gas could be used to assess and demonstrate EOR. This study has only examined pipeline transmission.

In practice the combination of options for capture, transport and storage will be optimised to minimise costs and take account of such factors as location, duration and volume of gas to be handled and the timing of demand from EOR schemes. It is probable that a network of pipelines will be developed linking power stations to oil and gas fields. This will smooth supply and demand from point sources and minimise the infrastructure investment attributed to any one project. An overall analysis of such a system was beyond the range of this scoping study. Therefore to make a realistic assessment of the potential costs a set of case studies, describing possible implementation options, has been evaluated, as listed in Table E1 and E2.

Table E1 Case Studies Used to Assess the Economic Performance of Carbon Dioxide EOR Schemes.

Case 1	• Carbon dioxide capture by retrofitting to an existing coal fired power station in Central Scotland to supply 500MMscft/day (317kg/sec). • Pipeline transport over land to NE Scotland 200km (Cruden Bay). • Sub-sea transport to an oil field cluster centred 170km offshore. • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each). • After 10 years a pipeline extension of 390km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).
Case 2	• Carbon dioxide capture by retrofitting to an existing coal fired power station in NE Yorkshire to supply 500 MMscft/day (317kg/sec). • Pipeline transport over land to Teeside 150km. • Sub-sea transport to oil fields centred 330km offshore • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each) • After 10 years a pipeline extension of 170km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).

Table E1 Case Studies Used to Assess the Economic Performance of Carbon Dioxide EOR Schemes (Cont.)

Case 3	• New build coal fired IGCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • Plant located within a 50km radius of where the carbon dioxide pipeline could come on shore at Teeside. • Four collection pipelines to take CO_2 from stations to main transmission pipeline on the coast. • Sub-sea transport to oil fields centred 330km offshore. • Other details as for Case 2.
Case 4	• New build natural gas fired GTCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • Other details as for Case 3
Case 5	• Carbon dioxide capture by retrofitting to existing gas fired GTCC power stations (4 stations) in Northern England to supply 500 MMscft/day (317kg/sec). • The 4 stations assumed to be an average of 50km from a pipeline node 150km from Teeside. • Pipeline transport over land to Teeside 150km. • Sub-sea transport to oil fields centred 330km offshore • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each) • After 10 years a pipeline extension of 170km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).

Table E2 Case Studies Used to Assess the Economic Performance of Carbon Dioxide Capture and Storage in Depleted Natural Gas Reservoirs

Case 6	• Carbon dioxide capture by retrofitting to an existing coal fired power station in NE Yorkshire to supply 500 MMscft/day (317kg/sec). • Pipeline transport over land to Humberside 50km. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to 10 individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.
Case 7	• New build coal fired IGCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • The 4 stations located within a 50km radius of where the carbon dioxide pipeline could come on shore. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to 10 individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.
Case 8	• New build natural gas fired GTCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • The 4 stations located within a 50km radius of where the carbon dioxide pipeline could come on shore. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to 10 individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.

Results

Results have shown significant uncertainty concerning the costs of carbon dioxide capture and storage. This arises from the generic nature of the data used, which have broad ranges applied to them to accommodate site specific variations. Also for EOR, there is considerable uncertainty over the yield and long market value of the oil produced. Nonetheless it is clear that injection into depleted gas fields is a more expensive option than EOR because this has no offsetting benefit from oil production.

The costs and level of CO2 emissions abatement attainable with CCS schemes is sensitive to the benchmarks against which they are assessed. In this study the costs of carbon dioxide capture have been evaluated against two benchmarks:

- The increased cost of electricity generation of the capture technology compared to the cost of generation from the same plant without capture technology.
- The increased cost of electricity generation from the capture plant compared to the generation cost of the most economic new build technology (i.e. the Long Run Marginal Cost plant), which was taken to be natural gas fired GTCC.

The first of these benchmarks considers a situation in which a decision has been made to build or refurbish a particular type of plant, and evaluates the additional cost of applying carbon dioxide capture to that type of plant. The second benchmark considers a position where the capture technology is built in preference to the most economic generation option (i.e. not taking into account carbon dioxide emissions), which in this study was assumed to be GTCC.

The level of carbon dioxide emissions that are abated is not equal to the quantity captured at the power station and used for EOR or injected into depleted natural gas fields. This is due to a combination of factors:

1. Carbon dioxide capture is only 85-90% efficient
2. The generation efficiency of the power plant with carbon capture is less than for normal plant and hence more fuel is used to produce the same amount of electricity.
3. Energy is used by gas compressors on the transmission pipeline that results in additional carbon dioxide emissions.
4. The level of abatement depends on the type of generation plant displaced by the capture plant.

With regard to the fourth point above, two benchmark emissions were used in assessing abatement. In line with the benchmarks used for costing capture, these were:

- The level of abatement gained by displacing the same plant without capture technology.
- The level of abatement gained by displacing the Long Run Marginal Cost technology, that is natural gas fired GTCC.

The second benchmark is not favourable for coal fired plant fitted with carbon dioxide capture because displacing GTCC from the electricity system has a smaller impact on emissions than displacing coal fired plant. However, it is a reasonable benchmark to use if gas fired GTCC is expected to be the preferred new capacity over the next one to two decades. In the discussion below capture and abatement costs estimated relative to the GTCC benchmark are reported with the corresponding values for the "same plant" benchmark given in brackets.

Costs for injection storage across the case studies ranged from £20-27/tCO_2 (£15-27/ tCO_2). Expressed per tonne of carbon dioxide abatement (i.e. the emissions avoided rather than the carbon dioxide captured) these costs increase to £34-93/tonne CO_2 (£18-41/tCO_2) or £125 – 341/tC (£66 – 150/tC). These latter values need to be used in comparing capture and injection into depleted gas fields with alternative greenhouse gas abatement options.

The uncertainties affecting the costs of capture with EOR based storage are greater than for injection storage because they include EOR yields and oil prices as well as capture and transmission costs. Sensitivity analyses showed that the economics of EOR are strongly dependent on the yield (i.e. tonnes of oil per tonne of carbon dioxide injected), oil price and the capital cost of the capture plant. With more optimistic assumptions there is potential for EOR to give a net positive return in its own right. This is particularly so for Case 3 involving construction of new IGCC capacity. These optimistic assumptions equate to constructing power plant or capture facilities to the central cost estimates and applying EOR to the most suitable fields giving the highest yields of oil per tonne of carbon dioxide injected. This suggests that EOR may already be economic with oil fields that are particularly well suited for EOR (i.e. give a high yield), and that a stable oil price above $20/bbl would also considerably improve prospects. It is not clear if sufficient of these oil fields exist to initiate investment in the infrastructure to support a full-scale carbon dioxide capture and EOR scheme. It seems more likely that, at least initially, such fields will be "picked off", possibly using tanker transport of carbon dioxide.

With central cost and performance values the study has shown that the economic gap (or additional cost for carbon dioxide storage over and above what may be paid by oil producers) for EOR ranges across the case studies from £4 - 10/t CO_2 (£(-2) – 11/ tCO_2). This gives a crude indication of the economic support that may be needed to encourage implementation of EOR. These results are broadly in line with other studies that have shown that some financial incentive is needed to stimulate implementation (Kinder-Morgan, 2002 and DTI, 2003). If this support was made available as part of a broader greenhouse gas abatement strategy the justification for any such intervention would be abatement of greenhouse gas emissions rather than EOR "per se". Therefore the assessment of costs needs to be done in relation to the carbon dioxide abated, which, as discussed above, is less than the amount captured and used for EOR. The abatement costs evaluated in the study ranged from £13 - 50/tCO_2 (£(-2) - 19/ tCO_2) or £48 - 183/tC (£(-7) - 70/tC).

Another way to consider the economic support is the average annual cost to support an 8Mt CO_2 per year EOR scheme over 20 years. Across the five case studies estimates based on central cost and performance data ranged from £32M to £80M per year.

It should be stressed that the above economic assessment concentrates solely on carbon dioxide abatement, however it should be recognised that EOR offers added benefits. These include:

- Increase recovery of UK oil reserves
- Extend oil field (and UK offshore oil industry) life

- Increase energy security
- Improve Balance of Payments
- Using CO_2 for EOR will free up large amounts of natural gas currently being used to sustain oil production (principally in Norwegian Sector fields); this gas would be available for export to UK as UK becomes increasingly reliant on imports [Needs to be confirmed]
- A major investment in the North Sea giving a boost to the local economy and jobs during redevelopment period

Barriers to Implementation

The scoping study identified three types of barrier affecting the implementation of carbon dioxide based EOR, namely:

- Organisation and division of risk
- Technical Uncertainty
- Market Uncertainty

Other potentially important barriers, not directly linked to the theme of this study, are regulation and international law, long term safety and public perception/acceptance.

Organisation and division of risk is a possible barrier because a full scale EOR scheme will require the participation of power generators, gas transporters, oil producers and government over a 20-30 year period. Projects will require considerable "up front" capital investment, but this is not divided evenly across the stakeholders. Investment for the power producers in carbon capture plant is highest, particularly if they decide on new plant rather than retrofit options. It is likely that some mechanism for distributing risk more evenly between stakeholders will be needed before projects can go ahead. Government is a stakeholder because the full-scale implementation of EOR probably depends on the payment of some form of credit (e.g. emissions permit trading, fiscal support) for the emissions abated. Industry stakeholders would need to confident that this arrangement would be maintained for the full 20-30 year duration of EOR for them to take the investment risk.

The economics of capture and storage are vulnerable to uncertainties concerning the technical performance and cost of key elements of the system. Most important are the yield of oil from EOR schemes and the capital cost of capture plant. Early capture and storage initiatives could focus on oil fields that are well suited for carbon dioxide based EOR and on capture technology that has least uncertainty over costs and performance. Nonetheless there will be a reluctance to take this risk unless the returns are sufficient to justify it.

Economics of capture and storage are sensitive to market prices, particularly for oil, but also for gas and coal. A standard approach for dealing with this would be to require projects to yield a positive return at a conservatively low oil price (e.g. conservative oil price of $16/bbl). Another standard commercial approach to the evaluation of such projects is to require a higher internal rate of return than for more mainstream projects. Both approaches would considerably reduce the economic attractiveness of the case studies covered herein.

Contents

1 Introduction

Capture and storage of carbon dioxide produced in the combustion of fossil fuels offers one option for attaining large scale reductions in the emissions of anthroprogenic greenhouse gases. This involves three basic stages; capture, transportation and injection into a storage medium. Carbon dioxide capture would be most efficiently applied to large "point sources" in order to gain economies of scale both in the capture process itself and in subsequent transportation and storage. Examples of such sources include fossil-fuelled power stations, oil refineries, petrochemical plant, cement works and iron & steel plant. Because of the large quantities of gas involved (i.e. of the order of 1 - 30 Mt/yr CO_2 for a full scale scheme) transportation is most likely to be by pipeline in preference to batch handling, although liquefied gas tankers have been suggested as an option for demonstration plant. Finally a range of storage options have been proposed, including injection into depleted oil and/or gas reservoirs, geological aquifers, deep unminable coal seams and on or below the deep ocean bed. Injection into oil/gas reservoirs and deep coal seams has the attraction of utilising geological formations with demonstrated storage capabilities[3]. They also have potential to generate an economic return through enhanced oil recovery (EOR) or enhanced coal-bed methane (ECBM) generation.

The UK currently derives 90% of its primary energy and generates over 70% of its electricity from fossil fuels (DTI, 2002). Moreover, it has access to substantial carbon dioxide storage capacity (IEA-GHG, 2002). In particular there is potential for storage combined with EOR in the oil fields in the central and northern North Sea areas, while the gas fields of the southern North Sea offer a large near shore resource for storage. Consequently capture and storage needs to be assessed as a major option for greenhouse gas abatement for the UK

This report describes the results of a scoping assessment for DTI, which was guided by the terms of reference for a "Scoping Study of Carbon Dioxide Separation and Storage" prepared for the TPUK Power Sector Working Group. The study has focused on carbon dioxide capture from power plant with the overall objective of developing a basic understanding of the economic case for both EOR and storage of carbon dioxide in the North Sea.

In line with the Terms of Reference the scoping study has approached this assessment by considering the 4 main factors affecting carbon dioxide capture and storage, namely:

1. Implementation Options
2. Operational Issues
3. Economic Assessment
4. Incentives and Barriers

[3] Coal seams hold significant quantities of methane

2 Implementation Options

Implementation of carbon capture and storage in the North Sea will involve the three basic steps discussed above; capture, transportation and storage. This section considers the technical options for each of these steps and identifies and justifies the selection of a limited set for assessment in this study.

2.1 CAPTURE

A broad range of options has been proposed for capturing carbon dioxide from fossil fuel power plant. These include:

1. Fitting capture equipment to an existing coal fired power station
2. Fitting capture equipment to an existing gas turbine combined cycle (GTCC) power station
3. Building a new coal fired power station that integrates carbon capture
4. Building a new gas turbine combined cycle power station that integrates carbon capture
5. Refurbishing an existing coal fired power station with higher efficiency super-critical boilers and fitting capture equipment
6. Building a coal gasifier integrating carbon capture technology and linking this to an existing gas turbine combined cycle plant.

Also for each of these generic options there is a range of engineering approaches available that are based on either pre or post combustion capture. For example fitting capture equipment to an existing coal fired power station could be done by installing scrubbing equipment to separate carbon dioxide from the other flue gases. Alternatively the power station could be converted to oxyfuel combustion with flue gas recycling, which increases considerably the concentration of carbon dioxide in the flue gas, making capture easier and more efficient. Similarly for new coal fired stations designs have been developed based on both pulverised coal combustion with super-critical boilers and integrated gasification combined cycle (IGCC). Furthermore there are a range of IGCC designs that differ for example in their use of heat recovery methods and whether the gas from the gasifier is burned directly in the turbine (with post combustion carbon dioxide capture) or first passed through a “shift” process to produce hydrogen (pre-combustion capture) (IEA-GHG, 2000a).

For the purpose of this study four of the capture options listed above were selected for assessment (options 1 to 4 above). These were chosen to give a “scoping assessment” of the potential range of economic costs across a range of capture methods. The study was not intended to make a comparison of the relative merits of alternative capture technologies (e.g. coal versus gas fired plant, post versus pre-combustion capture or retrofit versus new build). Indeed the generic technical and economic data available to the study typically indicated an uncertainty of +/-30%, which was linked to factors such as possible variations between locations and in the specification of the fuels to be used. This range of uncertainty almost encompasses the differences in the estimated costs of the technologies (see Section 4).

2.2 TRANSPORT

Carbon dioxide can be transported in gaseous, liquid or solid form. However, with the quantities to be handled (1-10Mt/yr) and distances involved (100-500km) for any single full-scale capture and storage project in the UK it is likely that pipeline transmission of "dense phase" carbon dioxide will be the preferred option. Certainly all existing large-scale transportation of carbon dioxide, which is mainly for land based EOR in the USA, is undertaken with pipelines.

An alternative would be to liquefy the carbon dioxide and use rail and ship transport. This could be deployed for off-shore EOR options relevant to the UK, and has the advantage of providing some "buffer" capacity to handle shut downs of either the power plant or the injection well heads[4]. In fact ship transport has been suggested as a possible method for demonstrating the use of carbon dioxide for EOR in the North Sea (Kinder Morgan, 2002). One drawback is that the liquefaction process uses a significant amount of energy, which, if supplied from fossil fuel sources, will reduce the amount of carbon dioxide abated.

This assessment has focused on full-scale deployment of capture and storage and therefore has only considered pipeline transportation.

2.3 STORAGE

The storage options covered by this assessment are EOR and one-off injection into depleted gas fields. These differ significantly in both their application and timing and need to be considered separately.

2.3.1 Enhanced Oil Recovery (EOR)

Depleted oil fields, as for the depleted gas fields considered below, offer a large capacity for carbon dioxide storage. This capacity can be exploited by injecting carbon dioxide at high pressure such that it displaces water and oil occupying the pore space of the host rock. In principle this could be implemented at any time, but for offshore oil fields there is a clear cost saving to be gained by undertaking operations when the existing production platforms and supporting infrastructures are in place. Furthermore, the injection of carbon dioxide can facilitate the extraction of additional oil (EOR). If the production facilities are still in place this oil can be transported to shore where it can be sold to offset some of the costs of carbon dioxide capture and storage.

Some UK North Sea oil fields have now been in production for over 30 years and it is probable that without the application of advanced EOR methods, of which carbon dioxide injection is one option, some will be decommissioned over the next decade. Therefore if full advantage is to be gained from the existing infrastructure, and an economic return is to be gained from additional oil revenues, EOR will also have to commence implementation over the next 10 years.

Accordingly this assessment has explicitly examined the near term implementation of carbon dioxide based EOR utilising existing facilities for oil production and transport.

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[4] Ship transportation of carbon dioxide purely for storage is barred by the OSPAR and London Conventions.

2.3.2 Injection into Depleted Gas Fields

Carbon dioxide injection into depleted natural gas fields is usually considered for fields that are fully depleted or abandoned. However, injection into operating fields to maintain or increase reservoir pressure thereby improving gas production is technically feasible although at present it is not normal practice.

Because enhanced production is not a major factor with injection into depleted gas fields there is less need for early implementation in order to use existing infrastructure. Also, because the operation does not have to be tailored to optimise additional production, the well head injection facilities are comparatively simple, and in the case of the UK's offshore fields could probably be sub-sea units not requiring the existing production platforms.

In principle the pipeline systems used to bring natural gas onshore from UK gas fields could be used to transport carbon dioxide for disposal. However, the practicality of this will depend on the condition of the pipelines, and clearly would only be possible if most gas production had ceased.

Taking account of the above this study has considered storage in UK depleted natural gas fields without any additional production of gas (i.e. a pure storage option), and with a new pipeline system to transport carbon dioxide. No specific timescale has been considered for this option.

3 Operational Issues

This section considers operational issues affecting carbon dioxide capture and storage, which need to be taken into account in the economic assessment.

3.1 CAPTURE

The main operational issue affecting carbon dioxide capture is to match output to the demand profile of the storage system. This is not an issue with injection into depleted gas fields, which can take gas when it is produced. However, with EOR a steady and reliable supply is required to support production. Two issues are important:

- The operational characteristics of power station carbon dioxide sources compared to oil production facilities.
- The reliability of the supply, transmission and demand chain.

Power stations may operate on base load (i.e. effectively 24h per day) or at a lower diurnal load factor depending on their cost competitiveness relative to other generation plant. Even base load stations do not operate 365 days in the year because of planned shutdowns for maintenance and unplanned shutdowns due to technical problems either with the generation plant or the transmission system. Overall a power station operating on base load will export electricity for 80 to 90% of the year with other power plant exporting for a smaller fraction.

Oil product platforms aim to operate continuously although once more this will be reduced by maintenance and unplanned shutdowns. Therefore an oil production facility operating with EOR will require carbon dioxide to be delivered for the order of 90% of the year.

Crudely there is a reasonable match between the demand for carbon dioxide for EOR and supply from power stations operating on baseload. This match could be enhanced by co-ordinating scheduled shutdowns of the power station and the oil production platforms. Also unplanned shutdowns should not present major problems provided they are not of long duration. If the oil production platform had to shutdown at short notice the power station could respond by continuing to operate but with the carbon dioxide capture plant off line. Similarly the oil production facility could respond to a loss of carbon dioxide supply by reverting to water injection, at least for Water Alternating Gas (WAG) EOR (see Section 3.3) (Woods, 2002).

In line with this position the study has considered a system in which carbon dioxide is captured from one or more power stations operating with a load factor of 80%. When considering retro-fitting capture equipment to existing stations it has been assumed that the power station will subsequently operate with a load factor of 80% even if its load factor before retrofitting was less than this. The implications of this for the cost of carbon capture are discussed later (Section 4).

3.2 TRANSMISSION

Pipeline systems have high reliability and it has been assumed in the study that they will not impose any limitations on the capture and storage system. Pipeline systems have been sized to meet the daily carbon dioxide requirements of the EOR and gas field storage schemes defined below (Section 4).

3.3 STORAGE

3.3.1 Enhanced Oil Recovery

The effectiveness of carbon dioxide based EOR depends on the characteristics of the oil reservoir and the physical properties of the oil to be extracted. Not all oil fields in the UK North Sea will yield additional production from this technique but a significant number will. A recent evaluation by the DTI's SHARP Project (Goodfield, 2002) has estimated an EOR potential in UK North Sea reservoirs of between 950 and 2250 MMSTB with an associated net carbon dioxide retention of about 700 Mt[5]. Other studies have suggested higher retention of the order of 2.6 Gt (BGS, 1996 and IEA, 2000b) and additional oil recovery potentials of 16,600 MMSTB for North Sea reserves covering the UK and Norway (IEA, 2000b).

Irrespective of the exact capacities involved the implementation of EOR is complicated by a combination of factors:

- It involves distributing carbon dioxide to a large number of oil reservoirs of differing size and hence carbon dioxide requirements.
- The oil fields are distributed over a large area of the North Sea.
- The timing at which carbon dioxide based EOR needs to start varies between fields depending on the time when they were first brought into production.
- The quantity of carbon dioxide required per barrel of oil produced differs between fields according to how well suited they are for EOR.
- Carbon dioxide is produced with the oil and needs to be separated and reinjected into the oil field. As a result, while gross demand for carbon dioxide from a single field may increase over the course of EOR, net demand for additional carbon dioxide will decline with time.
- The duration of a carbon dioxide EOR scheme can also vary from about 10 to 20 years.
- The timing for oil production from EOR differs depending on the type of approach adopted, which again is determined by the nature of the reservoir. Fields subject to Water Alternating Gas (WAG) EOR will produce oil within 1-2 years of the start of EOR operations, but this production will decline with time. In contrast Gravity Stabilised Gas Injection (GSGI) may not yield additional oil for several years and then produce larger volumes over a shorter timescale.

As a result of these factors the demand for carbon dioxide for EOR is subject to uncertainty and will vary with time as shown by results from the DTI's SHARP project presented in Figures 1 and 2.

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[5] These figures suggest average enhanced oil yields of 0.18 to 0.43 tonnes of oil per tonnes of CO_2, although this could be higher for the most favourable fields.

Figure 1 shows the cumulative net amount of carbon dioxide that could be used (and retained) in WAG EOR schemes assuming these could be implemented at any time up to their current Close of Production (COP) dates. This illustrates the window of opportunity for EOR as the amount of carbon dioxide falls as fields are closed. The estimates suggests an annual carbon dioxide demand of about 15Mt CO_2/yr averaged over 20 years. Because WAG EOR schemes can be implemented at any time up to the close of production (COP) date it is possible to phase their commissioning to produce a fairly steady demand for carbon dioxide. However, this demand will be the sum of varying demands from a number of fields that are be widely distributed geographically.

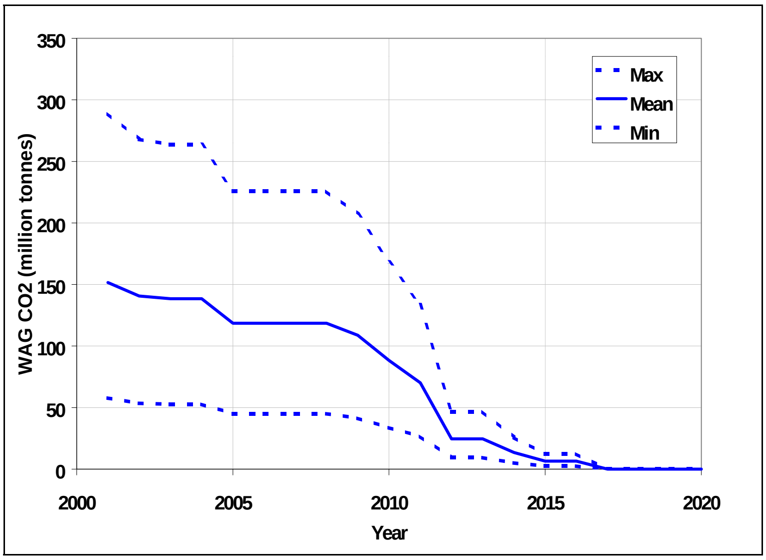


Figure 1 Cumulative WAG EOR Carbon Dioxide Retention Assuming the Window of Opportunity Closes at COP Dates (Goodfield, 2002)

Figure 2 shows the estimated carbon dioxide demand profile for GSGI EOR schemes in the UK North Sea. GSGI EOR needs to be implemented close to the field COP date and therefore does not offer the flexibility of WAG for smoothing carbon dioxide demand. The figure shows demand peaking at about 35Mt/yr in 2020.

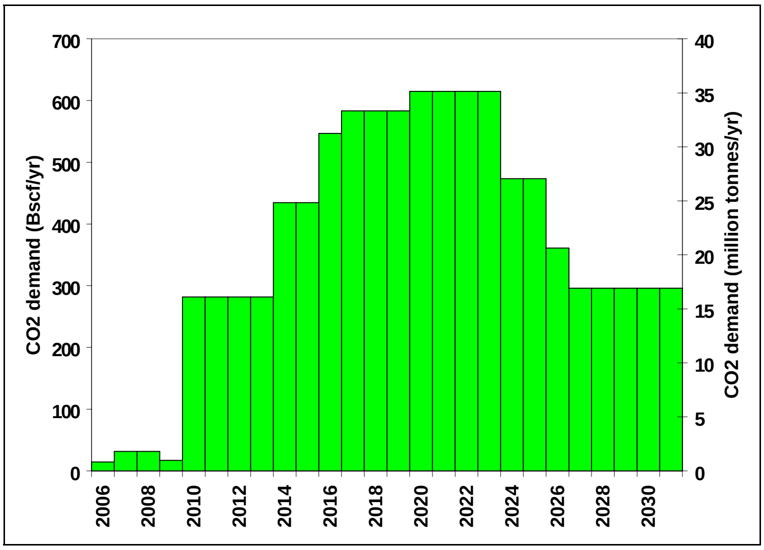


Figure 2 Illustrative Carbon Dioxide Requirement Profile for all Potential GSGI EOR Projects (Goodfield, 2002)

Overall these estimates suggest that total demand for carbon dioxide for EOR in UK North Sea oil fields could be about 10 Mt/yr up to 2010, increasing to about 25 Mt/yr from 2010-2015 and reaching a peak of 35 to 40 Mt/yr between 2015 and 2025. Further demand could come from other North Sea regions (e.g. Norway) which could help to smooth demand. However, the geographical distribution of this demand requires an integrated supply system to handle the changing demands of individual fields. Drawing parallels with the use of carbon dioxide for EOR in North America it has been proposed that this requirement could best be met with a pipeline transmission and distribution system serving the whole North Sea (Kinder Morgan – Elsam, 2002). This system would take carbon dioxide from several sources in the UK and Denmark making the supply system more robust to the operation of individual power plant.

A further complicating factor is that the carbon dioxide used in one EOR scheme could potentially be recovered and reused in a second scheme. Clearly this is not attractive from the viewpoint of carbon sequestration, but could be considered by oil companies as a way of minimising any expenditure they were incurring for their carbon dioxide supplies. This option has not been considered in this study.

Finally oil fields have the potential to hold more carbon dioxide than that needed for EOR such that additional storage could be achieved by continuing to inject after EOR is completed. This option also has not been considered explicitly in this study. However, it does support the simplifying assumption made in the Case Studies described below that carbon dioxide is injected at a constant rate over the duration of the EOR operation.

From the above background it will be clear that the implementation of carbon dioxide based EOR in the North Sea is a complex issue requiring detailed systems assessments that are beyond the scope of this study. Consequently to make some first order assessments of the economic and carbon dioxide balances of EOR in the North Sea some case studies have been examined based on the information above. These are introduced in Section 4.

3.3.2 Injection into Depleted Gas Fields

UK natural gas fields are situated in the Southern North Sea with pipelines coming ashore at Easington, Threddlethorpe and Bacton. It has been estimated that the carbon dioxide storage capacity of these fields is about 4880 Mt (BGS, 1996). Unlike EOR it is probable that storage in these fields would be implemented when they were fully depleted and therefore the issue of a “window of opportunity” does not arise.

Again the storage capacity is spread across an appreciable number of fields and therefore for large-scale storage a transmission and distribution pipeline network will most probably be required. Because the relatively pure and dry carbon dioxide separated from power plant is not particularly corrosive there is the possibility of using some of the existing pipeline infrastructure that brings natural gas on shore. However, it is not clear how much of this will be used for the fields that remain in production or for import of gas from other regions. Therefore the central assumption in this scoping study has been that a new pipeline system will be needed.

4 Economic Assessment

This scoping study has aimed to make a first order evaluation of the overall costs, and cost breakdown between stages (i.e. capture, transmission and storage), of implementing carbon dioxide capture and storage schemes based on EOR and injection into depleted natural gas reservoirs. As discussed in Section 3.3 fully integrated systems are likely to be needed to implement capture and storage in an optimal manner. However, analysis of such systems is beyond the scope of this study. Instead the evaluation has considered a set of Case Studies that have been designed to examine a range of implementation options and thereby scope the likely costs. These Case Studies are described below together with the additional assumptions needed to facilitate their analysis.

4.1 ENHANCED OIL RECOVERY

4.1.1 Case Studies

The following Case Studies have been undertaken:

Case 1	• Carbon dioxide capture by retrofitting to an existing coal fired power station in Central Scotland to supply 500MMscft/day (317kg/sec). • Pipeline transport over land to NE Scotland 200km (Cruden Bay). • Sub-sea transport to an oil field cluster centred 170km offshore. • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each). • After 10 years a pipeline extension of 390km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).
Case 2	• Carbon dioxide capture by retrofitting to an existing coal fired power station in NE Yorkshire to supply 500 MMscft/day (317kg/sec). • Pipeline transport over land to Teeside 150km. • Sub-sea transport to oil fields centred 330km offshore • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each) • After 10 years a pipeline extension of 170km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).
Case 3	• New build coal fired IGCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • Plant located within a 50km radius of where the carbon dioxide pipeline could come on shore at Teeside. • Four collection pipelines to take CO_2 from stations to main transmission pipeline on the coast. • Sub-sea transport to oil fields centred 330km offshore. • Other details as for Case 2.
Case 4	• New build natural gas fired GTCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • Other details as for Case 3
Case 5	• Carbon dioxide capture by retrofitting to existing gas fired GTCC power stations (4 stations) in Northern England to supply 500 MMscft/day

	(317kg/sec). • The 4 stations assumed to be an average of 50km from a pipeline node 150km from Teeside. • Pipeline transport over land to Teeside 150km. • Sub-sea transport to oil fields centred 330km offshore • 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each) • After 10 years a pipeline extension of 170km to a second cluster of oil fields. • Again 40% of carbon dioxide distributed to smaller fields in a 50km radius from the central field through 4 smaller pipelines (10% each).

In addition to defining the case studies some assumptions had to be made to support the analysis. These covered capture, transmission and EOR and were as follows:

Generic Assumptions

- Each Case Study examines the supply of 500 MMscft/day (317 kg/sec) of carbon dioxide, which is sufficient for a practical scale EOR scheme.
- The rate of carbon dioxide import into the EOR scheme is constant during the full 20 years operation.
- Carbon dioxide is produced with the oil at a constant level equal to 50% of the rate of import and is compressed and reinjected (in practice CO_2 rejection would be less than 50% in the early years and more than 50% in later years of the scheme).
- The overall EOR scheme lasts for 20 years and is made up of two 10 year projects centred on different regions of the North Sea.
- The choice of locations for power plant and oil fields is arbitrary and is intended to investigate the impact of location on costs.
- A constant EOR yield of 0.37 tonnes oil per tonne of imported carbon dioxide has been assumed for all case studies (i.e. towards the upper end of the SHARP Project estimates reported in section 3.3.1).
- An operating period of 80% per year has been assumed for all case studies
- To gain some comparability between studies the fossil fuel prices used in the study were take from the "Long Term Low Carbon Options Study" undertaken for DTI (FES, 2002). These were:
  - Power Station Coal £30.5/t
  - Power Station Natural Gas 23p/therm (£2.17/GJ)
  - Oil Beach Price $20/bbl

Capture

- Costs and energy assumptions include compression to 110 bar
- For retrofit options the original power plant capital cost was assumed sunk for coal plant and to be written down by 50% for the GTCC plant.
- CO_2 abatement was assessed relative to the corresponding plant without capture and against new build natural gas fired GTCC plant[6].

[6]Strictly the carbon dioxide abatement achieved should be assessed relative to the emission from whatever type of plant would have generated the electricity if the carbon capture plant had not been commissioned. There are various options for the "displaced plant" depending on the generation costs of different plant and the amount of surplus capacity available to the system. The two options for displaced plant considered herein are (a) the same plant without capture facilities and (b) the plant with lowest long run marginal cost

- Capture cost was assessed relative to corresponding power plant generation cost without capture and against natural gas fired GTCC plant.
- With retrofit the output of the plant is reduced due to greater internal energy consumption for carbon dioxide separation and compression. It could be argued that this "lost" capacity will need to be replaced at times of peak demand, and that the cost of this additional peak capacity should be attributed to the carbon dioxide captured. However, the separation plant could be switch off at peak demand thus restoring maximum output. Therefore no costs for replacement capacity have been considered[7].

Transport

- Pipelines are sized to daily output of the carbon capture schemes (i.e. 500MMscft/day)
- Pipelines are extended to the second cluster of fields after 10 years
- The system operates for 20 years
- CO_2 emissions from energy use in pressure booster stations are estimated assuming gas turbine powered compressors
- It is assumed that there is no leakage of CO_2 from the pipeline system.

EOR

- There is a level net demand for CO_2 spread over the10 year operating period of each "area"
- CO_2 is compressed to 200 bar for injection and re-injection
- Off shore compression uses gas turbine power
- Oil is produced after 2 years of G_c =generation efficiency with capture technology fitted
- Injection and continues at a constant level for the remaining 8 years of each EOR scheme.
- Decommissioning of production platforms is delayed 5 years by EOR, which produces economic benefit by delaying the associated expenditure.
- The capital investment for EOR is £200M per area
- Cost of decommissioning production facilities is set equal to EOR capital cost[8].

(LRMC), which is the new capacity likely to be built on economic grounds without any consideration of carbon abatement.

[7] Another alternative would be only to operate the amine absorber, which uses comparatively little energy compared to that for absorber regeneration and carbon dioxide compression. The absorber could then be regenerated off-peak, thus capturing some, but not all of the carbon dioxide produced at peak periods.

[8] No data were available for decommissioning costs so this is a purely arbitrary assumption.

4.1.2 Results of Economic Assessment

Capture

The cost of carbon capture was calculated by attributing the additional cost of power generation from plant fitted with separation technology to the carbon dioxide captured. i.e.

$$\text{Capture Cost } (£/\text{t } CO_2) = \frac{(P_c - P_{nc})}{100(E_{ct} - E_c)}$$

where

P_c =generation cost from plant with carbon dioxide capture (p/kWh$_e$)

P_{nc} =generation cost without capture either from the actual plant or the LRMC plant (p/kWh$_e$)

E_{nc} =emission from plant without capture (kg/kWh$_e$)

E_{ct} =quantity of carbon dioxide produce in plant with capture (kg/kWh$_e$)

E_c=emission from plant with capture (kg/kWh$_e$)

The total quantity of carbon dioxide produced in the plant with capture equipment is higher than in the same plant without capture. This is because the capture equipment requires energy to operate, effectively reducing the generation efficiency of the plant, which consequently must burn more fuel to produce the same amount of electricity. The amount of carbon dioxide produced in the plant fitted with capture technology is given by:

$$\text{Carbon Dioxide Produced (kg/kWh}_e) = E_{nc} \times \frac{G_c}{G_{nc}}$$

where

G_c =generation efficiency with capture technology fitted

G_{nc} =generation efficiency without capture technology fitted

Baseline costs for carbon dioxide capture from the various plant options examined in the assessment are listed in Table 1. Most of the data collected on these options were claimed to have an uncertainty of about +/-30%. A similar level of uncertainty applies to these results.

Table 1 Carbon Dioxide Capture Costs for Different Types of Fossil Fuelled Power Generation Plant

	Cost Relative to Plant (£/t CO_2)	Cost Relative to LRMC (£/t CO_2)
Coal PF Retrofit 1	21	19
Coal PF Retrofit 2	21	16
New IGCC 1	8	13
New IGCC 2	18	34
New GTCC	21	21
GTCC Retrofit	19	14

The technology assessments were based on data published in (IEA, 2000) with the exception of IGCC 1, which is based on data from Jacobs Consultancy (Jacobs, 2002). The costs for the GTCC Retrofit were based on the additional costs and generation efficiency penalty of carbon dioxide capture, by amine scrubbing, applied to a new GTCC plant, but assuming that 50% of the original capital cost of the plant was "sunk".

The cost of capture was less for the coal PF (pulverised fuel) and GTCC retrofit options when assessed relative the LRMC plant rather than the plant themselves. This is because the generation cost of the LRMC plant, at 1.95p/kWh, was higher than the generation costs of the PF and existing GTCC plant (both without capture). In comparison the generation costs of the new coal plant were greater than the LRMC[9], and consequently the capture cost is higher when calculated relative to the LRMC plant.

Transport

Central costs for carbon dioxide transport for each of the case studies are listed in Table 2. These costs were estimated using the IEA-GHG Programme's spreadsheet costing model (IEA, 2002), which is designed to enable high level comparison of transport options. The values are likely to have an uncertainty of about +/- 25%.

Table 2 Cost of Transporting Carbon Dioxide by Pipeline from the Power Plant to the EOR Schemes

	Transport Cost (£/t)
Case 1 (PF)	6.9
Case 2 (PF)	7.6
Case 3 (New IGCC)	7.4
Case 4 (New GTCC)	7.4
Case 5 (Retro GTCC)	8.3

Enhanced Oil Recovery

The cost of implementing carbon dioxide based EOR has been estimated in a study of the Fulmar oil field by Genesis Consultants on behalf of DTI (Genesis, 2002). This estimated that offshore capital costs could range from £59M to £167M with an accuracy of +/- 40%. The range reflects uncertainty whether a new production platform will be needed or if the EOR facilities could be accommodated on the existing facility. It also reflects uncertainty over the size of the scheme and hence over the scale of equipment needed to handle both carbon dioxide injection and produced fluids. Capital costs for the case studies considered herein were scaled in proportion to the carbon dioxide injection rate from the Genesis estimates yielding a central value of £200M for each of the schemes included in each case study.

Genesis also provided estimates of EOR operating costs for a Fulmar based scheme of £1.4-2.0M/yr. The upper value was scaled in line with the level of oil production to give an operating cost of £8.6M/yr for both of the 10 year EOR schemes included in the case studies.

A final component in the economic assessment of EOR is the value of deferred decommissioning of production facilities. The extent to which decommissioning is

[9] The LRMC plant was assumed to be a new gas turbine combined cycles (GTCC) plant.

delayed will depend on the duration of the EOR scheme and when it is started in comparison to the COP date for the field. For the purpose of the scoping study it was arbitrarily decided that EOR would start 5 years before COP. Therefore with the EOR lasting 10 years decommissioning was taken to be delayed for 5 years. No data were available on the size of the decommissioning expenditure that would be delayed so this was assumed to be equal to the offshore investment in EOR (i.e. £200M).

Combining these factors the cost of CO_2 injection was calculated. Since the same assumptions were applied to each case study a value of £7.2/t CO_2 applies in all cases.

Economic benefits of the EOR schemes were estimated from the quantity of oil produced and the assumed oil price of $20bbl. This revenue was reduced in the last 5 years of each 10 year EOR campaign (i.e. after decommissioning would have occurred without EOR) by the general operating costs of the production facilities which were taken to be £63M/yr[10].

Bringing together the costs of capture, transmission and injection, and the value of the oil produced, the total costs and benefits (value of additional production) of each case study were calculated and baseline values are listed in Table 3.

Table 3 Total Discounted Costs and Revenues for the EOR Case Studies

	Cost (£M)	Revenue (£M)	Economic Gap (£M)
Case 1 (PF)	2457 (2661)	1817	639 (844)
Case 2 (PF)	2337 (2666)	1817	521 (849)
Case 3 (New IGCC)	2078 (1701)	1817	263 (-116)
Case 4 (New GTCC)	2587	1817	771
Case 5 (GTCC retro)	2582	1817	767

Note For consistency the central values in this table are based on cost estimates made relative to the LRMC plant. Costs measured relative to the specific plant are given in brackets; these values are the same for gas fired stations.

None of the case studies yield a net positive return with the costs, performance parameters and 10% discount rate used in the assessment. With the baseline values listed in the table the new build IGCC option appears most attractive. It should be recalled that there is a +/- 30% accuracy on the cost data used and there are similar uncertainties over other performance parameters (e.g. EOR yield) used in these case studies.

Carbon Dioxide Abatement

The quantity of carbon dioxide emissions abated in the case studies is not equal to the total quantity captured and used in EOR. This is due to a combination of factors:

- Carbon capture is only 85-90% efficient.
- The generation efficiency of the power plant with carbon capture is less than for normal plant and hence more fuel is used to produce the same amount of electricity.

[10] This value was estimated from values for total operating costs and oil production in 1999 given in "Development of UK Oil and Gas Resources 2000" (DTI, 2000).

- Energy is used by gas compressors on the pipeline and oil production platforms which result in additional carbon dioxide emissions.

The level of carbon dioxide abatement is given by the relationship:

$$\text{Net Abatement (tonnes/yr)} = \frac{(E_{nc} - E_c) \times O}{1000} - E_{pc} - E_{Oil}$$

where
E_{nc} = emission from plant without carbon dioxide capture (kg/kWh$_e$)
E_c = emission from plant with capture (kg/kWh$_e$)
O = annual electricity production from capture plant (kWh$_e$/yr)
E_{pc} = emissions from pipeline compressor energy consumption (tonnes/yr)
P_c = emission from oil platform compressor energy consumption (tonne/yr)

Results for the case studies are given in Table 4. These results highlight the importance of what benchmark technology is used to assess abatement. When this is assessed relative to the same plant without carbon dioxide capture all the options appear reasonably effective with abatement of 59-77% of the quantity of gas used for EOR. In comparison when the assessment is made relative to the expected LRMC plant (i.e. natural gas fired GTCC) the coal fired options look less effective with abatement of only 17-27% of the gas used for EOR. This is because the gas fired LRMC plant emits less carbon dioxide per unit of electricity generated than the coal fired plant before capture technology is fitted.

Abatement Cost

Drawing the results from the above sections together the overall cost for carbon dioxide capture and storage through EOR can be assessed. Two costs can be considered:

- The support cost per tonne of carbon dioxide delivered for EOR, calculated by dividing the net cost of the scheme (Table 3) by the total discounted amount of carbon dioxide used. This indicates the additional support needed, over and above what oil producers may pay for carbon dioxide, in order to make the overall scheme cost neutral. In other words it is a measure of the economic gap for implementing carbon dioxide based EOR as a purely commercial operation unrelated to emissions abatement. (A negative value indicates the scheme offers a net positive return without support)
- The cost per tonne of carbon dioxide abated, calculated by dividing the net cost of the scheme by the total discounted amount of carbon dioxide emissions abated. This is the cost of avoiding carbon dioxide emissions with capture and storage through EOR and is the value to be compare to other carbon dioxide abatement options.

Both of these values are listed in Table 5 for each of the case studies.

Table 5 Carbon Dioxide Disposal and Abatement Costs for the Case Studies

	Support Cost of CO_2 for EOR (£ /t CO_2)	Abatement Cost vs Plant (£ /t CO_2)	Abatement Cost vs LRMC plant (£ /t CO_2)
Case 1 (PF)	11	19	50
Case 2 (PF)	11	19	35
Case 3 (New IGCC)	-2	-2	13
Case 4 (New GTCC)	10	14	14
Case 5 (GTCC retro)	10	13	13

Cost of carbon dioxide for EOR is calculated relative

The results show that the most cost-effective source of carbon dioxide for EOR would be a new IGCC plant. IGCC plant is also most cost effective for abatement when the assessment is made against the same type of plant without capture technology. However, when the assessment is made against the LRMC plant, new GTCC technology (Case 4) and existing GTCC with retrofit capture (Case 5) have comparable costs. In the case of the GTCC plant this is because of the higher net abatement attainable with gas fired generation due to the inherently lower emissions from gas combustion compared to coal.

Table 4 Assessment of the Net Abatement of Carbon dioxide Attained in Each of the EOR Case Studies

	Annual emission with capture (Mt/yr)	Annual Emission without capture (Mt/yr)	Annual Emission of LRMC plant without capture (Mt/yr)	Emission from Pipeline Compressors (Mt/yr)	Emission from EOR Compressors (Mt/yr.)	Net Abatement relative to Plant (Mt/yr)	Net Abatement Relative to LRMC Plant (Mt/yr)	Abatement as a percentage of CO_2 sent for EOR Relative to Plant (%)	Abatement as a percentage of CO_2 sent for EOR Relative to LRMC Plant (%)
Case 1 (PF)	0.9	5.9	2.6	0.08	0.30	4.7	1.4	59	17
Case 2 (PF)	0.9	6.1	2.8	0.07	0.30	4.8	1.6	61	20
Case 3 (New IGCC)	1.2	7.9	4.0	0.12	0.30	6.3	2.2	79	27
Case 4 (New GTCC)	1.2	7.7	7.7	0.12	0.30	6.1	6.1	76	76
Case 5 (Retro GTCC)	1.2	7.7	7.7	0.13	0.30	6.1	6.1	76	76

Table 7 Assessment of the Net Abatement Attained in Each of the Storage Case Studies

	Annual emission with capture (Mt/yr.)	Annual Emission without capture (Mt/yr.)	Annual Emission of LRMC plant without capture (Mt/yr.)	Emission from Pipeline (Mt/yr.)	Net Abatement relative to plant (Mt/yr.)	Net abatement Relative to LRMC Plant (Mt/yr.)	Percentage of CO_2 sent for Storage Relative to Plant (%)	Percentage of CO_2 sent for Storage Relative to LRMC Plant (%)
Case 6 (PF)	0.9	6.1	2.8	0.03	5.2	1.9	65	24
Case 7 (New IGCC)	1.2	7.9	4.0	0.08	6.7	2.5	83	31
Case 8 (New GTCC)	1.2	7.7	7.7	0.08	6.4	6.4	80	80

4.2 INJECTION INTO DEPLETED GAS FIELDS

4.2.1 Case Studies

The following case studies have been examined.

Case 6	• Carbon dioxide capture by retrofitting to an existing coal fired power station in NE Yorkshire to supply 500 MMscft/day (317kg/sec). • Pipeline transport over land to Humberside 50km. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.
Case 7	• New build coal fired IGCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • The 4 stations located within a 50km radius of where the carbon dioxide pipeline could come on shore. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.
Case 8	• New build natural gas fired GTCC plant (4 stations) for carbon dioxide capture to supply 500 MMscft/day (317kg/sec). • The 4 stations located within a 50km radius of where the carbon dioxide pipeline could come on shore. • Sub-sea transport to gas fields centred 100km offshore • Carbon dioxide distributed to individual disused gas fields in a 50km radius from pipeline hub through 10 smaller pipelines (10% each). • Gas injection pressure of 100 bar.

In addition to defining the case studies some assumptions had to be made to support the analysis. These covered capture, transmission and injection and were as follows:

Generic Assumptions

- Each Case Study examines the steady supply of 500 MMscft/day (317 kg/sec) of carbon dioxide over 20 years.
- An operating period of 80% per year has been assumed for all case studies.
- The overall scheme lasts for 20 years
- Fuel price assumptions are the same as for EOR discussed above.

Capture

- Assumptions are the same as for the EOR schemes.

Transport

- Assumptions are the same as for the EOR schemes.

Injection

- CO_2 delivered at 100 bar which is assumed to be sufficient for injection.

- Capital investment for well injection facilities assumed to be £50 M in total.
- Operating cost for well injection assumed to be £2.5M/yr in total

4.2.2 Results of Economic Assessment

Capture

The capture costs were the same as for the corresponding technologies in the EOR cases that are presented in Table 1.

Transport

Central costs for carbon dioxide transport for each of the case studies are listed in Table 6. These costs were estimated using the IEA-GHG Programme's spreadsheet costing model (IEA, 2002), which is designed to enable high level comparison of transport options. The values are likely to have an uncertainty of about +/- 25%.

Table 6 Cost of Transporting Carbon Dioxide by Pipeline from the Power Plant to the Injection Sites

	Transport Cost (£/t CO_2)
Case 5 (PF)	4.5
Case 6 (New IGCC)	5.7
Case 7 (New GTCC)	5.7

Injection

With the assumptions on capital and operating costs for injection facilities described above the discounted cost of injection was £1/tonne.

Carbon Dioxide Abatement

The quantity of carbon dioxide emissions that are abated in the case studies is not equal to the quantity captured at the power station and injected into the natural gas field. This is due to a combination of factors:

- Carbon dioxide capture is only 85-90% efficient
- The generation efficiency of the power plant with carbon capture is less than for normal plant and hence more fuel is used to produce the same amount of electricity.
- Energy is used by gas compressors on the transmission pipeline that results in additional carbon dioxide emissions.

The level of carbon dioxide abatement is given by the relationship:

$$\text{Net Abatement (tonnes/yr)} = \frac{(E_{nc} - E_c) \times O}{1000} - E_{pc}$$

where

E_{nc} = emission from plant without carbon dioxide capture (kg/kWh)

E_C = emission from plant with capture (kg/kWh)

E_{pc} = emissions from pipeline compressor energy consumption (tonnes/yr)

O = annual output from plant (kWh/yr)

Results for the case studies are given in Table 7. As for EOR these results highlight the importance of what baseline technology is used to assess abatement. When this is assessed relative to the same plant without carbon dioxide capture all the options appear reasonably effective with abatement of 64-83% of the quantity of the gas injected. In comparison when the assessment is made relative to the expected LRMC plant (i.e. natural gas fired GTCC) the coal fired options look less effective with abatement of only 24-31% of the gas injected.

Abatement Cost

Drawing the results from the above sections together the overall costs for carbon dioxide capture and storage are reported in Table 8. The higher abatement cost for coal fired power stations, when assessed relative to the LMRC plant, reflect the inherently higher emissions for coal compared to gas fired power plant.

Table 8 Carbon Dioxide Disposal and Abatement Costs for the Case Studies Examining Storage in Depleted Gas Fields

	Disposal Cost vs Plant (£ /t CO_2)	Abatement cost vs Plant (£ /t CO_2)	Abatement cost vs LRMC plant (£ /t CO_2)
Case 6 (PF)	26	41	93
Case 7 (New IGCC)	15	18	65
Case 8 (New GTCC)	27	34	34

4.3 SENSITIVITY ANALYSES

The costs for EOR and storage presented above were based on single values for a range of parameters each of which can have a significant effect on the outcome of the analysis. Most of these parameters are subject to uncertainty. These uncertainties are linked to both project and market factors the most important of which are:

Project factors

- Load factor of project
- EOR yield (i.e. tonnes of oil per tonne of carbon dioxide)
- Capital costs of capture plant
- Capital costs of EOR plant

Market factors

- Oil price
- Natural gas price
- Coal price

A sensitivity analysis has been undertaken to assess their impact on the baseline costs for EOR. Results from this analysis are presented in Figure 3 and Table 9 and are discussed individually below.

Load factor of the project refers to the proportion of the year during which the overall project (capture, transport and EOR) operates, and was assumed to be 80% in the central calculations. Varying this parameter by 10 percentage points from 70% to 90% had a significant effect on overall costs with coal fired plant for which abatement costs were changed by ± £10 to £15 per tonnes of CO_2. The abatement costs for gas fired plant were less sensitive, varying by about ± £5/ tCO2.

EOR Yield (i.e. tonnes of oil produced per tonnes of CO_2 injected) also has a direct affect on the economic return of EOR projects. This parameter will vary between oil fields and there was considerable uncertainty in determining an average value for this assessment. The central value of 0.36 is less than that used in other studies, which have been up to 0.5 tonnes of oil per tonne carbon dioxide. Increasing the yield by 30% over the central value to 0.48 caused all three of the coal case studies to attain positive net returns. With the lower yield of 0.24 the cost of abatement increased appreciably over the central value.

Capital Cost of the capture plant was most important for Case 3 (new IGCC), because of the higher total capital investment involved with this option. Varying capital costs by ± 30%, the range of uncertainty given by the data sources, altered carbon dioxide abatement costs by ± £13-17/t CO_2 for Cases 1 and 2 and by about ± £20/t CO_2 for Cases 3. The two case studies involving GTCC plant were less sensitive to capital cost uncertainties, varying by ± £3-4/t CO_2.

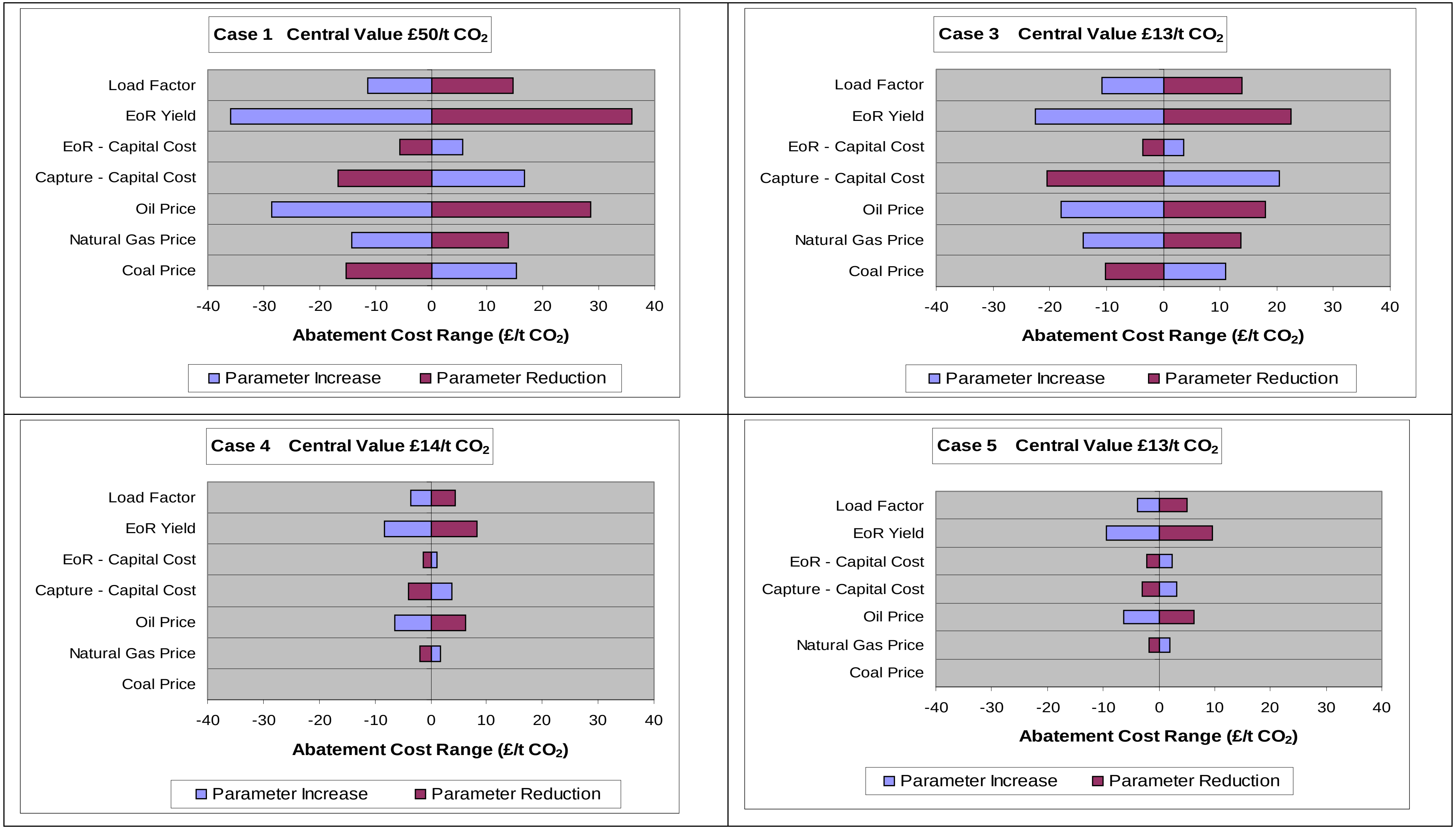
Capital Cost of EOR plant is very uncertain with a possible range of ± 40% placed on the estimates for one specific field (Genesis, 2002), and potential for greater field to field variations. However, because the EOR plant is a small part of the overall capital investment this uncertainty has less impact (± £2-5/t CO_2) on total abatement costs for all the cases studied (Figure 3).

Oil Price affects the economic return from all EOR projects. A central value of $20/bbl was used in the assessment but higher and lower values could be proposed based on historic variations and scenario projections (IEA, 2002; EEC, 2002). Results in Table 9 show that a variation of ± 20% around this value had a considerable effect on the economics of EOR particularly for the coal based case studies, changing abatement costs by ± £18-29/t CO_2.

Natural Gas prices affect the economics of all case studies through their impact on either the price of electricity from the LRMC plant, that are assumed to be displaced by plant fitted with capture technology, or from GTCC plant fitted with carbon capture equipment. Gas prices could increase over the decade as consumption expands across Europe, and therefore the central price used in the analysis of 23p/therm could be exceeded. Changing the natural gas price by ± 20% changed the abatement cost for coal plant, when measured relative to LRMC plant, by about ± £14/t CO_2. The same price variation had less affect with Cases 4 and 5 (GTCC plant), altering the abatement cost by about ± £2/t CO_2. Note the natural gas price change works in opposite directions for coal and gas fired plant; an increase in gas prices favouring the economics of the coal fired plant.

Coal Price affects the economics of Cases 1 to 3 since more coal is used in plant fitted with carbon dioxide capture equipment compared to non-capture plant to produce the same amount of electricity. A central price of £30.5/t was used in the analysis, but, although coal prices are likely to be more stable than oil or gas, it is possible that lower prices could be obtained in medium term. The impact of changing coal prices by ± £5/t was to alter abatement cost by up to ± £11-15/t CO_2.

Viewed overall it is clear that oil price and EOR yield consistently had a strong effect on the emissions abatement costs. The capital cost of the capture plant was also a sensitive variable with the coal fired options, particularly Case 3 the new build IGCC, because this option involved a higher proportion of capital expenditure. Cases 4 and 5 involving GTCC plants were least sensitive to parameter variations (Figure 3). It is also noteworthy that in absolute terms the economic gap for EOR is less sensitive to parameter changes than abatement costs (Table 9).



Note Case 2 is not included because it shows the same trends as Case 1

Figure 3 Impact of Parameter Variations on the costs of Carbon Dioxide Abatement in the EOR Case Studies

Table 9 Results of Sensitivity Analyses for Case Studies 1 to 5

Parameter/Case Study	Support Cost of CO_2 for EOR (£/t CO_2)	Abatement Cost vs LRMC plant (£/t CO_2)
Project Load Factor (80%+/- 10% points)		
Case 1	14 - 11 - 9	65 - 50 - 39
Case 2	14 - 11 - 9	48 - 35 - 26
Case 3	(-1) - (-2) - (-3)	27 - 13 - 2
Case 4	14 - 10 - 8	18 - 14 - 10
Case 5	14 - 10 - 7	18 - 13 - 10
EOR Yield (0.36t/t CO_2 +/- 30%)		
Case 1	17 - 11 - 5	86 - 50 - 14
Case 2	17 - 11 - 5	66 - 35 - 4
Case 3	5 - (-2) - (-7)	36 - 13 - (-10)
Case 4	17 - 10 - 4	22 - 14 - 5
Case 5	18 - 10 - 0	23 - 13 - 4
Capital Costs of Capture (+/- 30%)		
Case 1	9 - 11 - 14	34 - 50 - 67
Case 2	9 - 11 - 14	23 - 35 - 48
Case 3	0 - (-2) - (-3)	(-7) - 13 - 33.4
Case 4	7 - 10 - 13	10 - 14 - 17
Case 5	8 - 10 - 13	10 - 13 - 17
Capital Costs of EOR (+/- 40%)		
Case 1	10 - 11 - 12	45 - 50 - 56
Case 2	10 - 11 - 12	30 - 35 - 40
Case 3	(-3) - (-2) - 0	9 - 13 - 17
Case 4	9 - 10 - 11	12 - 14 - 15
Case 5	9 - 10 - 12	11 - 13 - 16
Oil Price ($20/bbl +/- $4)		
Case 1	16 - 11 - 6	79 - 50 - 22
Case 2	16 - 11 - 7	60 - 35 - 11
Case 3	3 - (-2) - (-6)	31 - 13 - (-5)
Case 4	15 - 10 - 6	20 - 14 - 7
Case 5	15 - 10 - 5	20 - 13 - 7
Coal Price (£30.5/t +/- £5/t)		
Case 1	10 - 11 - 12	35 - 50 - 65
Case 2	11 - 11 - 12	22 - 35 - 49
Case 3	(-2) - (-2) - 1	3 - 13 - 24
Case 4	Not Affected	Not Affected
Case 5	Not Affected	Not Affected
Natural Gas Price (£2.17/GJ +/- 10%)		
Case 1	Not Affected	64 - 50 - 36
Case 2	Not Affected	48 - 35 - 22
Case 3	Not Affected	27 - 13 - (-1)
Case 4	9 - 10 - 12	12 - 14 - 15
Case 5	9 - 10 - 12	12 - 13 - 15

4.4 OVERALL COST UNCERTAINTY FOR EOR

The previous section has shown that there is a range of project and market factors that can have a significant impact on the economic balance of EOR schemes. To scope the overall implication of these uncertainties, further analysis has been made in which all project factors (i.e. capital costs, load factor and EOR yield) were varied together from their most optimistic to most pessimistic values, to give the overall range of costs. Figure 4 shows the results in terms of proportions of the abatement cost ranges giving a positive or negative net return from the project. For example 15% of the cost range for Case 1 gives a net positive return. (N.B While this analysis has been done on the costs of carbon dioxide abatement a similar trend was obtained with the cost of carbon dioxide supplied for EOR)

Figure 4 shows that with the core assumptions on fossil fuel prices a net positive return is obtained for less than half of the potential cost range with all of the case studies. Case 3 (new IGCC) has the highest proportion of the cost range with a positive net return (36%).

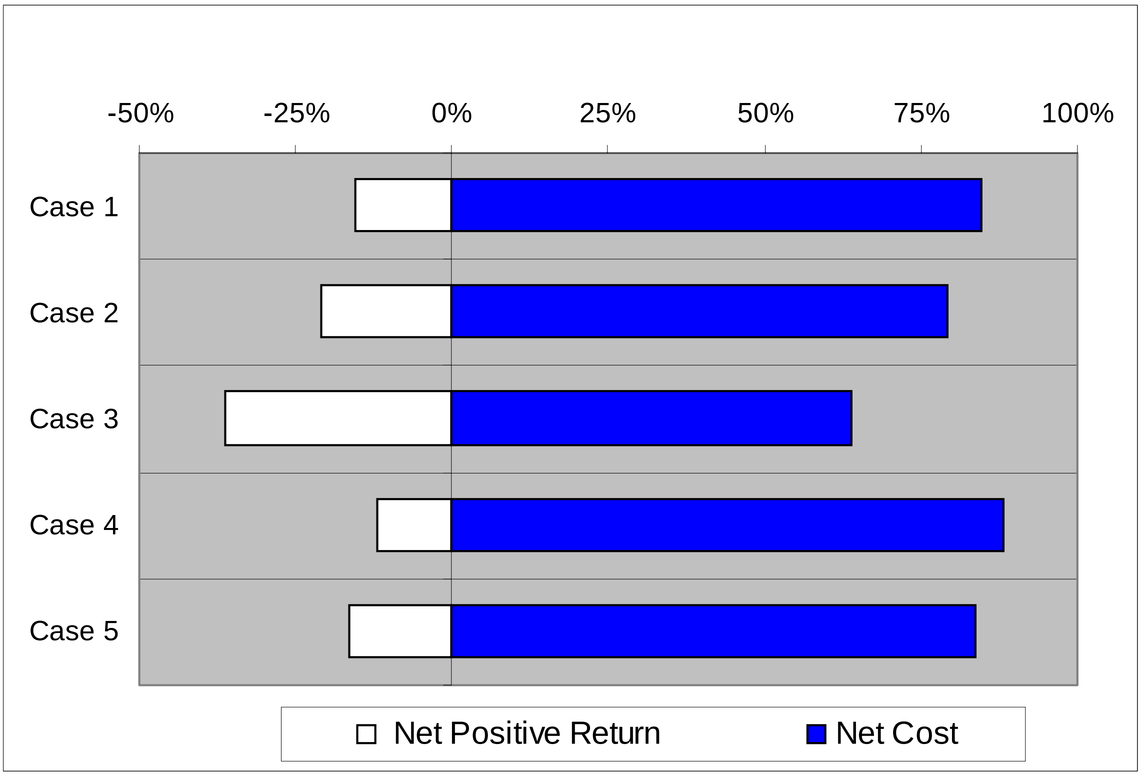


Figure 4 Proportion of the cost range for each Case Study giving a positive net return (core assumptions on fossil fuel prices)

The same analysis has been done for a scenario with higher fossil fuel prices. This involved increasing oil and gas prices by 20% from \$20 to \$24 per bbl for oil and from 23 to 27.5p/therm respectively, while holding coal prices steady. The assumptions underlying this scenario were that supply-demand balance for coal was unlikely to result in any significant price changes over the medium term, while growing demand for gas and oil could result in higher prices. Results in Figure 5 show that these changes significantly increased the proportion of the potential cost range giving a net positive return for the coal-based case studies (e.g. to 63% for IGCC). The GTCC based case studies were less affected by these changes in fossil fuel prices.

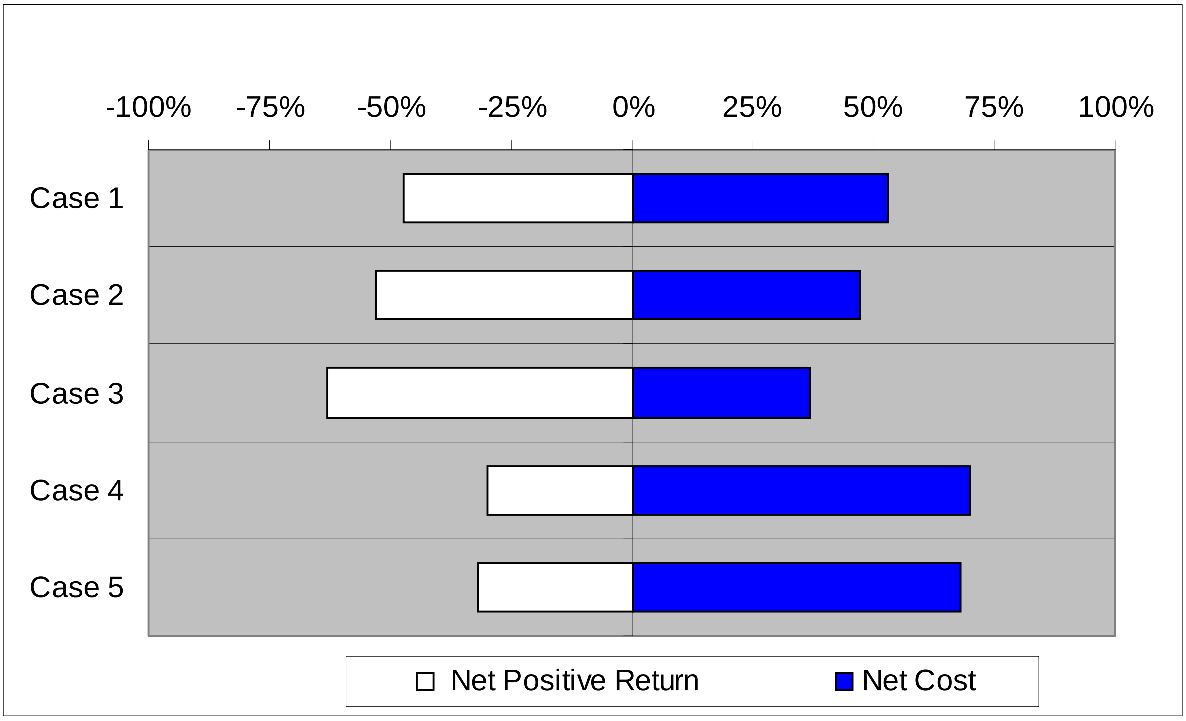


Figure 5 Proportion of the cost range for each Case Study giving a positive net return (increased fossil fuel prices)

5 Barriers to Implementation

This section considers some of the barriers to implementation of carbon dioxide capture and storage through EOR or injection into depleted gas fields. It is not intended to be comprehensive since some important barriers lie outside the remit of this scoping study (e.g. regulations, environmental impact and risk, public perceptions and acceptance). The aim is to consider those issues that have been identified and highlighted in collecting information and undertaking the analysis described above.

The barriers to implementation apparent from this study can be grouped under the headings:

- Organisation and division of risk
- Technical Uncertainty
- Market Uncertainty

5.1 ORGANISATION AND DIVISION OF RISK

The organisation of carbon dioxide capture and storage, particularly with EOR, requires collaboration between power producers, gas shippers, oil producers and government over a 20-30 year timescale. Projects will require considerable “up front” capital investment, but this is not divided evenly across the stakeholders as shown in Table 10. Investment for the power producers in carbon capture plant is highest, particularly if they decide on new plant rather than retrofit options (Cases 3 and 4). It is likely that some mechanism for distributing risk more evenly between stakeholders will be needed before projects can go ahead.

Government has been included in the list of stakeholders because the full scale implementation of carbon dioxide based EOR is likely to depend on the payment of some form of credit (e.g. emissions permit trading) for the emissions abated. The other stakeholders would need to confident that this arrangement would be maintained for the full 20-30 year duration of EOR for them to take the investment risk.

Table 10 Capital Investment During the First 10 Years in Each of the EOR Case Studies (£M)

	Case 1	Case 2	Case 3	Case 4	Case 5
Capture	643	576	1334	1566	1075
Transport	257	340	318	318	363
EOR	200	200	200	200	200

5.2 TECHNICAL UNCERTAINTY

As shown by the sensitivity analyses, the economics of capture and storage are vulnerable to uncertainties concerning the technical performance and cost of key elements of the system. Most important are the yield of oil from EOR schemes and the capital cost of capture plant. Early capture and storage initiatives could focus on oil fields that are well suited for carbon dioxide based EOR and on capture technology that has least uncertainty over costs and performance. Nonetheless there will be a reluctance to take this risk unless the returns are sufficient to justify it.

5.3 COMMERCIAL UNCERTAINTY

The sensitivity analysis has also shown that the economics of capture and storage are sensitive to market prices, particularly for oil, but also for gas and coal. A standard approach for dealing with this would be to require projects to yield a positive return at a conservatively low oil price. Results in Table 9 show that at an oil price of $16/bbl none of the case studies delivered a net economic return, and the financial gap was quite large when measure in term of a carbon abatement cost.

5.4 OVERALL TREATMENT OF RISK

The above subsections really highlight different aspects of the risk and uncertainty of novel capture and storage projects. A standard commercial approach to the evaluation of such projects is to require a higher internal rate of return than for more mainstream projects. The impact of this approach on the economics of EOR projects can be gauged by using a higher discount rate in the economic assessment. Table 11 shows the impact of moving from the 10% discount rate used in the assessments reported previously to a value of 15%. This considerably reduces the economic attractiveness of the case studies covered herein.

Table 11 Impact of Discount Rate of the Cost of Carbon Dioxide Abatement Cost Assessed Relative to LRMC Plant (£ /t CO_2)

	Case 1	Case 2	Case 3	Case 4	Case 5
DR 10%	50	35	13	14	13
DR 15%t	78	59	44	23	23

6 Conclusion

This scoping study has examined the implementation, operation, economics and barriers to undertaking carbon dioxide capture and storage in the UK. It has concentrated on carbon dioxide capture from fossil fuel power stations; large “point sources” of the gas that would need to be tackled in order to deliver significant levels of greenhouse gas abatement. Options for gas capture considered are retrofitting equipment to existing coal and natural gas fired plant as well as the construction of new coal (IGCC) and gas (GTCC) technology. Economic assessments have been made with “present day” costs, and do not consider future improvements through technical innovation and “learning by doing”, the potential of which is considerable for the less mature carbon capture technologies.

A range of options for gas storage have been proposed for the UK including injection into depleted oil and/or gas reservoirs, geological aquifers, deep unminable coal seams and on or below the deep ocean bed. The two options for storage considered in the study are utilisation for Enhanced Oil Recovery (EOR) and injection into depleted natural gas fields. EOR has the attraction of offering an economic return from additional oil production that will at least partially offset the cost of capture and storage. The two options have different timescales. Gas injection utilises near shore fields and requires comparatively little offshore infrastructure, and can be undertaken as and when it is needed within an integrated national greenhouse gas abatement strategy. In contrast EOR needs to be initiated before oil fields reach close of production, which for some of the early fields is before 2010. Therefore decisions have to be made on a shorter timescale with EOR, otherwise the capacity for storage will gradually decline as fields are closed.

It should be noted that the option of returning to abandoned oil fields at some later date to use them purely for storage does remain available. However, many UK oil fields are further offshore than the gas fields and therefore would be less attractive both technically and economically as a pure disposal option and would be used later. Returning to abandoned oil fields to implement EOR is unlikely to be economic since the production and transport infrastructure for oil would have been decommissioned.

Options for transporting the large quantities of carbon dioxide involved in full scale capture and storage (i.e. 1-30Mt/yr) are likely to be limited to pipeline systems although ship transport of liquefied gas could be used to assess and demonstrate EOR. This study has only examined pipeline transmission.

In practice the combination of options for capture, transport and storage will be optimised to minimise costs and take account of such factors as location, duration and volume of gas to be handled and the timing of demand from EOR schemes. It is probable that a network of pipelines would be developed linking power stations to oil and gas fields. This will smooth supply and demand from point sources and minimise the infrastructure investment attributed to any one project. An overall analysis of such a system was beyond the range of this scoping study. Therefore to make a realistic assessment of the potential costs a set of case studies, describing possible implementation options, has been evaluated.

Results have shown significant uncertainty concerning the costs of carbon dioxide capture and storage. This arises from the generic nature of the data used, which have broad ranges applied to them to accommodate site specific variations. Also for EOR, there is considerable uncertainty over the yield and long market value of the oil produced. Nonetheless it is clear that injection into depleted gas fields is a more expensive option than EOR because this has no offsetting benefit from oil production.

The costs and level of CO2 emissions abatement attainable with CCS schemes is sensitive to the benchmarks against which they are assessed. In this study the costs of carbon dioxide capture have been evaluated against two benchmarks:

- The increased cost of electricity generation of the capture technology compared to the cost of generation from the same plant without capture technology.
- The increased cost of electricity generation from the capture plant compared to the generation cost of the most economic new build technology (i.e. the Long Run Marginal Cost plant), which was taken to be natural gas fired GTCC.

The first of these benchmarks considers a situation in which a decision has been made to build or refurbish a particular type of plant, and evaluates the additional cost of applying carbon dioxide capture to that type of plant. The second benchmark considers a position where the capture technology is built in preference to the most economic generation option (i.e. not taking into account carbon dioxide emissions), which in this study was assumed to be GTCC.

The level of carbon dioxide emissions that are abated is not equal to the quantity captured at the power station and used for EOR or injected into depleted natural gas fields. This is due to a combination of factors:

5. Carbon dioxide capture is only 85-90% efficient
6. The generation efficiency of the power plant with carbon capture is less than for normal plant and hence more fuel is used to produce the same amount of electricity.
7. Energy is used by gas compressors on the transmission pipeline that results in additional carbon dioxide emissions.
8. The level of abatement depends on the type of generation plant displaced by the capture plant.

With regard to the fourth point above, two benchmark emissions were used in assessing abatement. In line with the benchmarks used for costing capture, these were:

- The level of abatement gained by displacing the same plant without capture technology.
- The level of abatement gained by displacing the Long Run Marginal Cost technology, that is natural gas fired GTCC.

The second benchmark is not favourable for coal fired plant fitted with carbon dioxide capture because displacing GTCC from the electricity system has a smaller impact on emissions than displacing coal fired plant. However, it is a reasonable benchmark to use if gas fired GTCC is expected to be the preferred new capacity over the next one to two decades. In the discussion below capture and abatement costs estimated relative to the

GTCC benchmark are reported with the corresponding values for the “same plant” benchmark given in brackets.

Costs for injection storage across the case studies ranged from £20-27/tCO_2 (£15-27/ tCO_2). Expressed per tonne of carbon dioxide abatement (i.e. the emissions avoided rather than the carbon dioxide captured) these costs increase to £34-93/tonne CO_2 (£18-41/tCO_2) or £125 – 341/tC (£66 – 150/tC). These latter values need to be used in comparing capture and injection into depleted gas fields with alternative greenhouse gas abatement options.

The uncertainties affecting the costs of capture with EOR based storage are greater than for injection storage because they include EOR yields and oil prices as well as capture and transmission costs. Sensitivity analyses showed that the economics of EOR are strongly dependent on the yield (i.e. tonnes of oil per tonne of carbon dioxide injected), oil price and the capital cost of the capture plant. With more optimistic assumptions there is potential for EOR to give a net positive return in its own right. This is particularly so for Case 3 involving construction of new IGCC capacity. These optimistic assumptions equate to constructing power plant or capture facilities to the central cost estimates and applying EOR to the most suitable fields giving the highest yields of oil per tonne of carbon dioxide injected. This suggests that EOR may already be economic with oil fields that are particularly well suited for EOR (i.e. give a high yield), and that a stable oil price above $20/bbl would also considerably improve prospects. It is not clear if sufficient of these oil fields exist to initiate investment in the infrastructure to support a full-scale carbon dioxide capture and EOR scheme. It seems more likely that, at least initially, such fields will be “picked off”, possibly using tanker transport of carbon dioxide.

With central cost and performance values the study has shown that the economic gap (or additional cost for carbon dioxide storage over and above what may be paid by oil producers) for EOR ranges across the case studies from £4 - 10/t CO_2 (£-2 – 11/ tCO_2). This gives a crude indication of the economic support that may be needed to encourage implementation of EOR. These results are broadly in line with other studies that have shown that some financial incentive is needed to stimulate implementation (Kinder-Morgan, 2002 and DTI, 2003). If this support was made available as part of a broader greenhouse gas abatement strategy the justification for any such intervention would be abatement of greenhouse gas emissions rather than EOR “per se”. Therefore the assessment of costs needs to be done in relation to the carbon dioxide abated, which, as discussed above, is less than the amount captured and used for EOR. The abatement costs evaluated in the study ranged from £13/t to £50/tCO_2 (£-2 to +19/ tCO_2) or £48 to £183/tC (£-7 to +70/tC).

Another way to consider the economic support is the average annual cost to support an 8Mt CO_2 per year EOR scheme over 20 years. Across the five case studies estimates based on central cost and performance data ranged from £32M to £80M per year.

It should be stressed that the above economic assessment concentrates solely on carbon dioxide abatement, however it should be recognised that EOR offers added benefits. These include:

- Increase recovery of UK oil reserves
- Extend oil field (and UK offshore oil industry) life
- Increase energy security

- Improve Balance of Payments
- Using CO_2 for EOR will free up large amounts of natural gas currently being used to sustain oil production (principally in Norwegian Sector fields); this gas would be available for export to UK as UK becomes increasingly reliant on imports [Needs to be confirmed]
- A major investment in the North Sea giving a boost to the local economy and jobs during redevelopment period

The scoping study identified three types of barrier affecting the implementation of carbon dioxide based EOR, namely:

- Organisation and division of risk
- Technical Uncertainty
- Market Uncertainty

Other potentially important barriers, not directly linked to the theme of this study, are regulation and international law, long term safety and public perception/acceptance.

Organisation and division of risk is a possible barrier because a full scale EOR scheme will require the participation of power generators, gas transporters, oil producers and government over a 20-30 year period. Projects will require considerable "up front" capital investment, but this is not divided evenly across the stakeholders. Investment for the power producers in carbon capture plant is highest, particularly if they decide on new plant rather than retrofit options. It is likely that some mechanism for distributing risk more evenly between stakeholders will be needed before projects can go ahead. Government is a stakeholder because the full-scale implementation of EOR probably depends on the payment of some form of credit (e.g. emissions permit trading, fiscal support) for the emissions abated. Industry stakeholders would need to confident that this arrangement would be maintained for the full 20-30 year duration of EOR for them to take the investment risk.

The economics of capture and storage are vulnerable to uncertainties concerning the technical performance and cost of key elements of the system. Most important are the yield of oil from EOR schemes and the capital cost of capture plant. Early capture and storage initiatives could focus on oil fields that are well suited for carbon dioxide based EOR and on capture technology that has least uncertainty over costs and performance. Nonetheless there will be a reluctance to take this risk unless the returns are sufficient to justify it.

Economics of capture and storage are sensitive to market prices, particularly for oil, but also for gas and coal. A standard approach for dealing with this would be to require projects to yield a positive return at a conservatively low oil price (e.g. conservative oil price of $16/bbl). Another standard commercial approach to the evaluation of such projects is to require a higher internal rate of return than for more mainstream projects. Both approaches would considerably reduce the economic attractiveness of the case studies covered herein.

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Appendix A
Details of EOR Case Studies

Appendix A Detailed Results for EOR Case Studies

Carbon Dioxide Capture		Case 1	Case 2	Case 3	Case 4	Case 5
Power Plant		PF Coal	PF Coal	IGCC	GTCC	GTCC retro
Power Plant Costs						
Capital (£ /kW) (Note 1)		100.0	50.0	625.0	269.3	134.6
Opex Fixed (£ /kW)		21.0	20.5	19.8	9.6	9.6
Opex Variable (p/kWh)		0.1	0.1	N/A	N/A	N/A
Load Factor (%)		80.0	80.0	80.0	80.0	80.0
Original Generation Efficiency of plant (%)		36.0	38.0	41.0	56.2	80.0
CO_2 produced per kWh(e) (kg/kWh)	$\mathbf{E_{nc}}$	0.84	0.80	0.74	0.37	0.37
Capture Plant Costs						
Capital for additional NOx/SOx Scrubbers (£ /kW)		50.0	50.0	N/A	N/A	N/A
Capital cost of capture plant (£ /t/h)		0.3	0.3	N/A	N/A	N/A
Capital cost of capture plant (£ /kW)		417.2	385.1	850.6	511.4	350.9
Opex of capture plant (£ /t)		6.3	6.3	N/A	N/A	N/A
Opex of capture plant (p/kWh) (Note 2)		0.5	0.5	0.4	0.3	0.3
Carbon Dioxide Capture Efficiency %)		90.0	90.0	85.0	84.5	84.5
Generation Efficiency with CO_2 capture (%)		24.0	26.0	35.5	47.2	47.2
CO_2 produced per kWh(e) (kg/kWh)	$\mathbf{E_{ct}}$	1.27	1.17	0.86	0.44	0.44
CO_2 released per kWh(e) (kg/kWh)	$\mathbf{E_{c}}$	0.13	0.12	0.11	0.06	0.06
CO_2 captured per kWh(e) (kg/kWh)		1.14	1.05	0.75	0.38	0.38
Coal Price (£ /t)		30.5	30.5	30.5	N/A	N/A
CO_2 Pressure (bar)		110.0	110.0	110.0	110.0	110.0
Cost of generation without capture (p/kWh)	$\mathbf{P_{nc}}$	1.6	1.5	2.3	1.9	1.8
Cost of generation with capture (p/kWh)	$\mathbf{P_{c}}$	4.1	3.7	2.9	2.7	2.5
Cost of generation from LRMC plant (p/kWh)		1.9	1.9	1.9	1.9	1.9
From Main Report Eqn 1						
Cost of Capture rel to plant (£ /t)		**21.4**	**20.8**	**8.0**	**20.8**	**19.3**
Cost of Capture rel to LRMC (£ /t)		**18.7**	**16.4**	**12.9**	**20.8**	**14.2**

Appendix A Detailed Results for EOR Case Studies (Cont.)

Carbon Dioxide Abatement		**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
Electricity production from capture plant (TWh/yr.)	**O**	7.0	7.6	10.7	20.9	20.9
CO_2 produced in capture plant (Mt/yr.)	$\mathbf{E_{ct} \times O}$	8.9	8.9	9.2	9.2	9.2
CO_2 released from capture plant (Mt/yr.)	$\mathbf{E_{c} \times O}$	0.9	0.9	1.2	1.2	1.2
CO_2 produced in plant without capture (Mt/yr.)	$\mathbf{E_{nc} \times O}$	5.9	6.1	7.9	7.7	7.7
CO_2 produced in LMRC plant (Mt/yr.)		2.6	2.8	4.0	7.7	7.7
Total CO_2 captured		8.0	8.0	8.0	8.0	8.0
From Main Report Eqn 3						
Abatement Relative to Plant (Mt/yr.)		5.0	5.2	6.8	6.5	6.5
Abatement Relative to LRMC plant (Mt/yr.)		1.7	1.9	2.8	6.5	6.5
Abatement as a percentage of CO_2 captured						
Relative to Plant (%)		63.0	64.9	84.6	81.4	81.4
Relative to LRMC Plant (%)		21.4	24.1	34.8	81.4	81.4
Cost of Abatement at plant - rel to plant (£ /t)		**34.0**	**32.1**	**9.4**	**25.6**	**23.7**
Cost of Abatement at plant - rel to LRMC plant (£ /t)		**87.4**	**68.4**	**36.9**	**25.5**	**17.4**

Appendix A Detailed Results for EOR Case Studies (Cont.)

Details of Carbon Dioxide Pipeline (First 10 years)		**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
Capacity of main pipeline (kg/sec)		317	317	317	317	317
Utilisation per year (%)		80	80	80	80	80
Carbon dioxide transported (Mt/yr.)		8	8	8	8	8
Length Onshore (km)		194	149	50 (x4)	50 (x4)	149+50(x4)
Length Offshore (km)		167	327	327	327	327
Inlet pressure (bara)		100	100	100	100	100
Outlet pressure on production platform		70	70	70	70	70
Number of Boost Stations		0	1	1	1	1
Capacity of distribution pipelines (kg/sec)		32	32	32	32	32
Number of distribution pipelines		4	4	4	4	4
Total Capital Cost (£M)		412.7	545.3	508.1	508.1	581.3
Opex Fixed (£M/yr.)		11.2	13.1	14.3	14.3	17.1
Opex Variable (£M/yr.)		4.9	4.7	5.4	5.4	6.3
Compression energy requirements (MW)		10.8	10.3	20.2	20.2	22.3
Associated CO_2 release (Mt/yr.)		0.05	0.05	0.09	0.09	0.10
Details of Pipeline Extension After 10 years						
Capacity of main pipeline (kg/sec)		317.0	317.0	317.0	317.0	317.0
Additional Length Subsea (km)		386.0	170.0	170.0	170.0	170.0
Capacity of distribution pipelines (kg/sec)		31.7	31.7	31.7	31.7	31.7
Number of distribution pipelines		4.0	4.0	4.0	4.0	4.0
Total Additional Capital Cost (£M)		506.8	327.7	327.7	327.7	581.3
Total Opex Fixed (£M/yr.)		17.1	15.9	17.1	17.1	0.0
Total Opex Variable (£M/yr.)		7.6	6.9	7.6	7.6	0.0
Compression energy requirements (MW)		6.2	16.3	26.2	26.2	28.3
Associated CO_2 release (Mt/yr.)		0.08	0.07	0.12	0.12	0.13
Levelised Cost of Transport (£/t)		**6.9**	**7.6**	**7.4**	**7.4**	**8.3**

Appendix A Detailed Results for EOR Case Studies (Cont.)

Details of Enhanced Oil Recovery		**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
Capital Cost of platform modifications (£M)		200	200	200	200	200
OPEX (£M/yr.)		8.4	8.4	8.4	8.4	8.4
Operating Availability (%)		80.0	80.0	80.0	80.0	80.0
Platform Decomm. Cost (£M)		200	200	200	200	200
Decommissioning delay (yrs)		5.0	5.0	5.0	5.0	5.0
Total NPV Cost of CO_2 injection for EOR (£M)		537.1	537.1	537.1	537.1	537.1
CO_2 Supply (Mt/yr.)		8.0	8.0	8.0	8.0	8.0
Discounted CO_2 Supply over 20 years (Mt)		74.9	74.9	74.9	74.9	74.9
Levelised Cost of CO_2 injection (£/t)		**7.2**	**7.2**	**7.2**	**7.2**	**7.2**
Injection pressure (bara)		200.0	200.0	200.0	200.0	200.0
Injection energy (MW)		6.2	6.2	6.2	6.2	6.2
Reinjection energy (MW)		63.3	63.3	63.3	63.3	63.3
Associated CO_2 Emission (Mt/yr.)		0.3	0.3	0.3	0.3	0.3
Oil Value ($/bbl)		20.0	20.0	20.0	20.0	20.0
Start of enhanced oil production		3rd Year	3rd Year	3rd Year	3rd Year	3rd Year
End of enhanced oil production		10th Year	10th Year	10th Year	10th Year	10th Year
Additional oil production (MMbbl/yr.)		21.6	21.6	21.6	21.6	21.6
NPV of oil produced (£M)		1815.6	1815.6	1815.6	1815.6	1815.6
Credit per tonne CO_2 injected (£/t)		**24.2**	**24.2**	**24.2**	**24.2**	**24.2**
NPV of EOR costs rel to plant (£M)		2661.7	2665.7	1701.5	2587.0	2582.2
NPV of EOR costs rel to LRMC plant (£M)		2454.6	2336.9	2078.3	2587.0	2582.2
Net Cost rel to plant (£M)		**846.1**	**850.1**	**-114.1**	**771.4**	**766.6**
Net Cost rel to LRMC plant (£M)		**639.0**	**521.3**	**262.7**	**771.4**	**766.6**

Appendix A Detailed Results for EOR Case Studies (Cont.)

SUMMARY	Case 1	Case 2	Case 3	Case 4	Case 5
Annual net abatement relative to plant (Mt CO_2/yr)	4.7	4.8	6.3	6.1	6.1
Annual net abatement relative to LRMC (Mt CO_2/yr)	1.4	1.6	2.2	6.1	6.1
Abatement as a percentage of CO_2 captured					
Relative to Plant (%)	58.6	60.6	79.3	76.1	76.3
Relative to LRMC Plant (%)	17.0	19.7	27.1	76.1	76.3
Total Discounted quantity of CO_2 injected (Mt)	74.9	74.9	74.9	74.9	74.9
Discounted quantity of CO_2 abated rel to original plant (Mt)	43.8	45.3	59.4	56.9	57.1
Discounted quantiy of CO_2 abated rel to LRMC plant (Mt)	12.7	14.7	20.2	56.9	57.1
Overall cost per tonne stored rel to plant (£ /t)	**11.3**	**11.3**	**-1.5**	**10.3**	**10.2**
Overall cost of Abatement rel to plant (£ /t)	**19.3**	**18.8**	**-1.9**	**13.6**	**13.4**
Overall cost per tonne stored rel to LRMC (£ /t)	**8.5**	**7.0**	**3.5**	**10.3**	**10.2**
Overall cost of Abatement rel to LRMC (£ /t)	**50.4**	**35.4**	**13.0**	**13.6**	**13.4**

Additional Assumptions

1. Capital cost for exisiting plant without capture is for life extension and for Case 1 fitting FGD.
2. Capital cost for coal reto fit includes additional acid scrubbers and carbon dioxide capture plant.
3. Gas compression is powered by turbines fuelled with natural gas
4. Power plant Capex for PF plant covers cost of refurbishment for 20 years operation, for retro GTCC covers residual capital plus refurbishment
5. Cases 3, and 4 assume CO_2 is collected from 4 power stations with an average distance of 50km from the coast
6. Case 5 assumes CO_2 is collected from 4 power stations with an average distance of 50km from the main pipeline node.
7. EOR yield assumed to be 0.364 tonne oil per tonne CO_2
8. EOR scheme assumed to take all platform Opex after 5 years operation
9. EOR Capex and Opex estimated from Geneis Oil & Gas Consultants report to DTI
10. Decommissioning cost assumed to be £200M and delayed for 5 years
11. Original power station CO_2 emission factors calculated from NAEI database
12. LRMC plant assumed to be GTCC

Appendix B
Details of Storage Case Studies

Appendix B Details of Storage Case Studies

Carbon Dioxide Capture		**Case 6**	**Case 7**	**Case 8**
Power Plant		PF Coal	IGCC	GTCC
CO2 Capture				
Power Plant Costs				
Capital (£/kW) (Note 1)		50.0	625.0	269.3
Opex Fixed (£/kW)		20.5	19.8	9.6
Opex Variable (p/kWh)		0.1	N/A	N/A
Load Factor (%)		80.0	80.0	80.0
Original Generation Efficiency of plant (%)		38.0	41.0	56.2
CO2 produced per kWh(e) (kg/kWh)	$\mathbf{E_{nc}}$	0.8	0.7	0.4
Capture Plant Costs				
Capital for additional NOx/SOx Scrubbers (£/kW)		50.0	N/A	N/A
Capital cost of capture plant (£/t/h)		0.3	N/A	N/A
Capital cost of capture plant (£/kw)		385.1	850.6	511.4
Opex of capture plant (£/t)		6.3	N/A	N/A
Opex of capture plant (£/kWh) (Note 2)		0.5	0.4	0.3
Carbon Dioxide Capture Efficiency %)		90.0	85.0	84.5
Generation Efficiency with CO2 capture (%)		26.0	35.5	47.2
CO2 produced per kWh(e) (kg/kWh)	$\mathbf{E_{ct}}$	1.2	0.9	0.4
CO2 released per kWh(e) (kg/kWh)	$\mathbf{E_{c}}$	0.1	0.1	0.1
CO2 captured per kWh(e) (kg/kWh)		1.1	0.7	0.4
Coal Price (£/t)		30.5	30.5	N/A
CO2 Pressure (bar)		110.0	110.0	110.0
Cost of generation without capture (p/kWh)	$\mathbf{P_{nc}}$	1.5	2.3	1.9
Cost of generation with capture (p/kWh)	$\mathbf{P_{c}}$	3.7	2.9	2.7
Cost of generation from LRMC plant (p/kWh)		1.9	1.9	1.9
From Main Report Eqn 1				
Cost of Capture rel to plant (£/t)		**20.8**	**8.0**	**20.8**
Cost of Capture rel to LRMC (£/t)		**16.4**	**12.9**	**20.8**

Appendix B Details of Storage Case Studies (Cont.)

Carbon Dioxide Abatement		**Case 6**	**Case 7**	**Case 8**
Electricity production from capture plant (TWh/yr)	**O**	7.6	10.7	20.9
CO2 produced in capture plant (Mt/yr)	$\mathbf{E_{ct} \times O}$	8.9	9.2	9.2
CO2 released from capture plant (Mt/yr)	$\mathbf{E_{c} \times O}$	0.9	1.2	1.2
CO2 produced in plant without capture (Mt/yr)	$\mathbf{E_{nc} \times O}$	6.1	7.9	7.7
CO2 produced in LMRC plant (Mt/yr)		2.8	4.0	7.7
Total CO2 captured		8.0	8.0	8.0
From Main Report Eqn 3				
Abatement Relative to Plant (Mt/yr)		5.2	6.8	6.5
Abatement Relative to LRMC plant (Mt/yr)		1.9	2.8	6.5
Abatement as a percentage of CO2 captured				
Relative to Plant (%)		64.9	84.6	81.4
Relative to LRMC Plant (%)		24.1	34.8	81.4
Cost of Abatement at plant - rel to plant (£ /t)		**32.1**	**9.4**	**25.6**
Cost of Abatement at plant - rel to LRMC plant (£ /t)		**68.4**	**36.9**	**25.5**

Details of Carbon Dioxide Pipeline		**Case 6**	**Case 7**	**Case 8**
Capacity of main pipeline (kg/sec)		317.0	317.0	317.0
Utilisation per year (%)		80.0	80.0	80.0
Carbon dioxide transported (Mt/yr)		8.0	8.0	8.0
Length Onshore (km)		50.0	50.0	50.0
Number of Onshore pipelines		1.0	4.0	4.0
Length Offshore (km)		100.0	100.0	100.0
Capacity of distribution pipelines (kg/sec)		31.7	31.7	31.7
Number of distribution pipelines		10.0	10.0	10.0
Total Capital Cost (£M)		383.5	500.5	508.1
Opex Fixed (£M/yr)		9.4	11.3	14.3
Opex Variable (£M/yr)		3.5	4.4	5.4
Compression energy requirements (MW)		7.9	18.3	20.2
Associated CO2 release (Mt/yr)		0.03	0.08	0.09
Levelised Cost of Transport (£ /t)		**4.5**	**5.7**	**5.7**

Appendix B Details of Storage Case Studies (Cont.)

Details of Injection		**Case 6**	**Case 7**	**Case 8**
Capital Cost of facilities (£M)		50	50	50
OPEX (£M/yr)		3	3	3
Operating Availability (%)		80	80	80
CO2 Supply (kg/sec)		317	317	317
Injection pressure (bara)		100	100	100
Annual net abatement relative to plant (Mt CO2/yr)		5.2	6.7	6.4
Annual net abatement relative to LRMC (Mt CO2/yr)		1.9	2.5	6.4
Discounted volume of CO2 stored		75	75	75
Discounted volume of CO2 abated relative to original plant (Mt)		48	62	60
Discounted volume of CO2 abated relative to GTCC (Mt)		18	23	60
Abatement as a percentage of CO2 captured				
Relative to Plant (%)		64.5	83.2	79.9
Relative to LRMC Plant (%)		23.6	30.9	79.9
Levelised cost of injection (£/t)		**1**	**1**	**1**
Summary				
Cost per tonne stored rel to plant (£/t)		**26**	**15**	**27**
Cost of Abatement rel to plant (£/t)		**41**	**18**	**34**
Cost per tonne stored rel LRMC (£/t)		**22**	**20**	**27**
Cost of abatement rel to LRMC/GTCC (£/t)		**93**	**65**	**34**

Additional Assumptions

1. Capital cost for exisiting plant without capture is for life extension and for Case 1 fitting FGD.
2. Capital cost for coal reto fit includes additional acid scrubbers and carbon dioxide capture plant.
3. Gas compression is powered by turbines fuelled with natural gas
4. Power plant Capex for PF plant covers cost of refurbishment for 20 years operation, for retro GTCC covers residual capital plus refurbishment
5. Cases 3, and 4 assume CO_2 is collected from 4 power stations with an average distance of 50km from the coast
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